Benefits of quantitative market research include:

- The ability to understand general customer communications preferences for purposes of future education efforts.
- The ability to track the level of customer understanding and value of AMS benefits throughout deployment process across the customer base.

ETI plans to conduct tracking surveys starting in Phase II of the deployment, compared against the Phase I baseline.

ETI has identified a number of key areas of customer responses that it will track throughout the course of the AMS deployment. These topics will be examined to ensure that ETI is effectively educating customers and responding to needs during the deployment.

Tracking of topics may include:
- Customer awareness of and sentiment toward energy management tools offered by advanced meters;
- Customer awareness of and sentiment toward advanced meters and their benefits; and
- Ongoing awareness of communications tools offered by ETI about AMS.

Segmentation

In its baseline research, ETI will poll a statistically valid sample of ETI's customers, including a diverse group representing all its different customer segments, regarding what they know about grid modernization and advanced meters. In addition to an appropriate customer sample representation, ETI will ensure that its customer sample embraces a demographically diverse pool of customers to participate in the study.

Within the sample size, ETI includes a representative sample of customers from the following customer segments:

1. Low income customers
2. Senior citizens
3. Non-computer users
4. Ethnic minorities and non-English speakers

This segmentation information will be important in developing unique communications to customers throughout the deployment.

Proposed Research Plan

The timeline for customer research will map to awareness and implementation for particular customers as follows:

Introduce	Pre-meter installation.	ETI Filing Date: 3Q 2017 Baseline survey followed by periodic surveys to monitor sentiment and customer attitudes.

Educate	Meter installation begins and access to online energy management information is made available.	Surveys directed to customers who have received an advanced meter. Surveys will start with deployment and carry on throughout the immediate post- activation period.
Engage	Approximately six months after meters are activated and at least six months of education has been conducted about how to use tools.	Surveys continue.

TIMING AND BUDGET

2016	**2017-18**	**2019-2021**	**Late 2021**	**2022 and beyond**
Early Phase I	**Phase I**	**Phase II**	**Phase III**	**Phase IV**
Education Planning	Pre-Deployment	Meter Deployment and Individual Activation of Online Energy Management Information and Tools	Energy Management Information and Tools Available to All Customers	Ongoing Engagement

	2016	2017	2018	2019	2020	2021	TOTAL
Stakeholder Education	$5,000	$5,000	$7,500	$10,000	$10,000	$7,500	**$45,000**
Customer Communications	$125,000	$125,000	$250,000	$1,000,000	$1,250,000	$550,000	**$3,300,000**
Email, SMS, web, mobile *Direct mail, printed collateral, bill inserts* *Content. social media, videos* *Paid media* *Creative development* *Program management*							
Community and Public Relations	$0	$15,000	$40,000	$50,000	$50,000	$40,000	**$195,000**
Partnerships and Events *Media Relations*							
Employee Education	$0	$7,500	$15,000	$15,000	$15,000	$15,000	**$67,500**
Market Research	$15,000	$50,000	$100,000	$125,000	$125,000	$100,000	**$515,000**
Market Research *Metrics Collection and Analysis*							
Flex Funds	$69,579	$12,079	$16,658	$26,165	$21,398	$23,199	**$169,078**
	$214.579	$214,579	$429,158	$1.226.165	$1,471,398	$735.699	**$4,291,578**

**Note: To provide flexibility as we execute the Customer Education Plan, ETI will use the Flex Funds as needed.*

APPENDIX A

This section provides detailed descriptions of certain education tools to be used in various phases.

Education Tool	Description
Website	Educational website content will be developed to educate customers and stakeholders about ETI's AMS deployment. This content will be phased to introduce new information as it becomes relevant and available to customers. It will also serve as an important tool throughout all phases of the education plan. The website tools will also enable ETI to use digital channels to direct customers to AMS information and limit effort to acquire information on the AMS deployment.
Email	We will leverage our customer email list to deliver timely, measurable messages to our customers throughout the deployment.
Informational toolkits – residential and small- and medium-sized business	Materials will be created with information about the deployment including an overview document, brochure, frequently asked questions (FAQ), etc. These toolkits will be used as appropriate to communicate messages to stakeholders and may be tailored as appropriate for specific audiences. For example, materials for small- and medium-sized businesses will be prepared to target information applicable to those customers.
Informational toolkit – large commercial and industrial	For large commercial and industrial customers, toolkits will be prepared for account executives to help inform businesses of the meter replacement schedule, the benefits of AMS, and what to expect along the way.
Presentations	Presentations will be prepared for public relations and customer service employees to communicate with stakeholder groups about

	information on the deployment and benefits of AMS.
Letters to customers	Customers will receive a letter informing them about planned installation of their new advanced meter, and any preparations close to their scheduled installation date.
Employee communications	ETI will create employee communications materials to explain the details and benefits of the deployment to employees. These communications will also educate employees on how to serve as ambassadors for the project with customers.
Videos	Videos will be created to explain the capabilities and benefits of the AMS technology.
Research	Baseline surveys and focus groups will be conducted to assess current and ongoing knowledge and attitudes towards AMS.
Community outreach	ETI will participate in community outreach events throughout Texas. To ensure customers will be able to have their AMS – related questions answered, a community outreach representative will be trained in AMS customer education strategies and will have details to answer questions about deployment.
Media relations	ETI will develop key talking points and FAQs to help with media response to inquiries about the AMS deployment, the capabilities of AMS technology and the benefits the AMS deployment is expected to provide ETI and its customers.
Display unit for events	Displays will be prepared to use at community outreach events to explain the benefits of AMS and information about the new advanced meters.
Digital marketing	ETI will utilize its digital marketing capabilities to support the customer education process.
Social media	Social media will be used to update customers about the AMS deployment and explain the benefits of advanced meters, as well as identify additional customer sentiment.
Search engine optimization (SEO)	In conjunction with web content created for the AMS deployment, SEO will be used to

	enable customers to find information about AMS generally, and ETI's AMS deployment in particular, when using web search engines.
Door hangers	Door hangers will be developed to use during meter installation. The door hangers will notify customers if their advanced meter was successfully installed or whether they need to call to schedule an installation. The back of the door hanger will also contain overview information about ETI's AMS deployment.
Installer cards/rack cards	Installer cards will be developed and provided to the meter installers to use if customers have questions in the field. Installer cards will contain overview information about ETI's AMS deployment and a few FAQs.
News release	ETI will develop news releases as needed throughout all phases of the deployment.
Telephone contact	Telephone contact may be made with customers throughout the deployment on a rolling basis and approximately 1-2 weeks before the customer's advanced meter installation.
Mass outreach	Once critical mass is achieved in the deployment of meters, ETI will launch multi-channel educational messages to target all demographics and customers who have received an advanced meter in order to reinforce availability of the new online information and benefits of the web portal.
Direct mail	Direct mail pieces will be developed to continue educating customers about the meter deployment and benefits of advanced meters. In addition, they will explain the new energy management information and benefits of the web portal. These direct mail pieces will target non-computer using customers, and provide instructions on what customers should do if they cannot access the new energy management information.
Bill inserts	Bill inserts will be developed to educate customers throughout the deployment, particularly those customers who do not access digital channels as frequently.
In-person courses	ETI will partner with community rganizations to educate customers about how to use online energy management tools. It will provide suggestions to customers on how they may be able to lower their monthly bill.

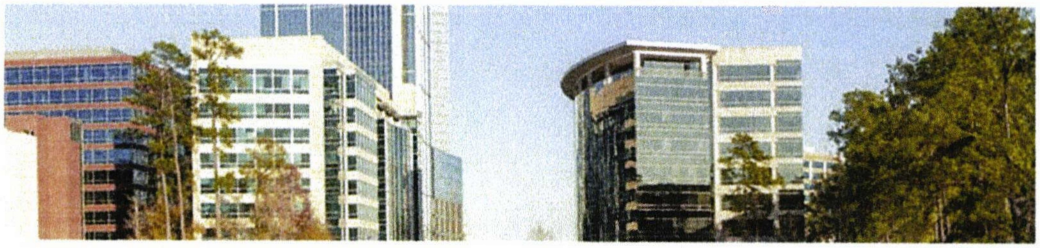
APPENDIX B

This section provides samples of educational materials for **illustrative purposes**. Actual information will be adjusted prior to dissemination based on design phase decisions and feedback from customers.

Web Page Mockups (Customers, Owners, Employees and Community Leaders)

Entergy.

Home Our Vision For Businesses Community



Our Vision

What is a Smarter Energy Future?

Our homes and our lives are benefiting daily from new technologies. Whether it is the convenience of using a mobile phone, paying your bills online, or using the Wi-Fi network in your local coffee shop, we all benefit from the advancements of technology.

As the local energy provider, we are in a position to use technology to make energy delivery more reliable and affordable. That is why we are pursuing a smarter grid in Texas that will offer you:

- Stronger and "smarter" localized electrical infrastructure to help improve community resiliency by helping us restore electricity in homes and businesses quicker after outages and potentially spot problems before they occur.
- More tools and better information to help customers understand and manage their energy use more effectively, which can lead to lower bills.
- Improved customer service, including better information that will allow us to answer customers' billing and service questions more quickly and effectively.
- Potential new programs to help further encourage and improve energy reduction and contribute to environmentally sustainable communities.

For more information about Entergy Texas' vision for a smarter energy future, call us at XXX XXX XXXX.

WE POWER LIFE™

Privacy Policy | Terms & Conditions

Installation Door Hanger (Residential Customers)

For illustrative purposes only

Date: ______________________________

Time: ______________________________

During our visit:

___ We upgraded your meter successfully

We were unable to upgrade your meter for one of the reasons below:

___ Need access to electric and/or gas meter

___ Meter blocked and/or obstructed

___ Locked fence or gate

___ Dog in the yard

___ Safety issue

___ Damaged equipment

___ Other:

Please call us at XXX-XXX-XXXX to return at a convenient time.

Entergy.

For illustrative purposes only

Building a Smarter Energy Future

Starts with a meter.

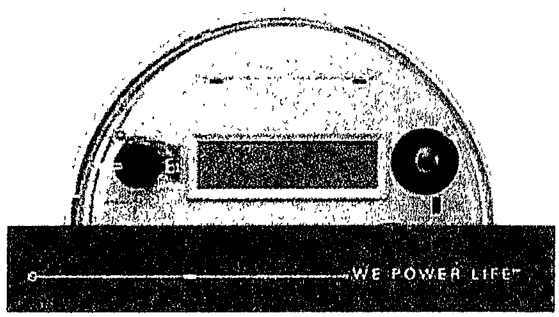
Entergy is upgrading our energy infrastructure to improve our communities. These upgrades begin with the installation of advanced meters.

Benefits include:

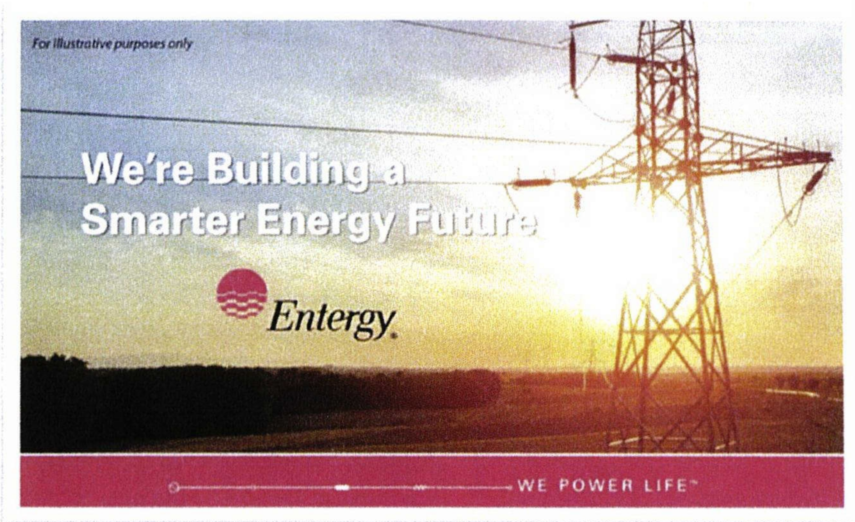
- Faster outage restoration after storms
- New tools to help you understand and manage your energy use more effectively
- Improved customer service

To learn more about our smarter energy future, visit energyfuturetexas.com or call us at XXX-XXX-XXXX with questions.

Entergy.



Installation Direct Mail (Residential Customers)



ENTERGY TEXAS, INC.
ADVANCED METERING SYSTEM
NON-STANDARD METERING SERVICE RATE DEVELOPMENT

Meter Choice	One Time Fee	Monthly Recurring	First Year Cost	Year 2 - Yearly Ongoing Cost
Customer keeps existing non-standard meter	$ 142.95	$ 29.71	$ 499.47	$ 356.53
Replace existing non-standard meter	$ 157.05	$ 29.71	$ 513.58	$ 356.53
Replace AMS meter with non-standard meter	$ 204.60	$ 29.71	$ 561.13	$ 356.53

ENTERGY TEXAS, INC.
ADVANCED METERING SYSTEM
NON-STANDARD METERING SERVICE RATE DEVELOPMENT
ONE-TIME CHARGE REVENUE REQUIREMENT

Option	CCS	Mailing	Locks	Trip Charge	Non-Standard Meter	Rate Case Expense	Total One Time Opt Out Charge
Keep Existing Meter	$ 36 91	$ 4 86	$ 21 47	$ 47.55	$ -	$ 32 16	$ 142 95
Replace existing meter with non-standard meter	$ 36 91	$ 4 86	$ 21.47	$ 47.55	$ 14 11	$ 32 16	$ 157 05
Replace AMS Meter with non-standard meter	$ 36 91	$ 4.86	$ 21 47	$ 95 10	$ 14.11	$ 32 16	$ 204 60

Opt Out Customers #	Total Meters	Reference
ETI	476,842	1,192

Trip Charge	Quanity	Unit of Measurement	Reference
Keep existing meter	1	Each	$ 47 55
Replace existing meter with non-standard meter	1	Each	$ 47 55
Replace AMS Meter with non-standard meter	2	Each	$ 95 10

Back Office	Quanity	Unit of Measurement	Price/unit
CCS Programming*	1	Each	44,000
Certified Letter Mailing	1	Each	$4.86

**Assumes a medium enhancement effort of ~400 hours @ $110/hr*

Material Costs	Quanity	Unit of Measurement	Price/unit	M&S Loader Rate	Cap Suspense Loader Rate	Total with Loaders
Refurbished non-standard digital meter	1	Each	$ 11 16	8 75%	16.25%	$ 14 11
Locking Band/Barrel Lock	1	Each	$ 16 98	8.75%	16 25%	$ 21 47

Rate Case Expense	Total	Price/unit
ESI Labor	46,164	
Entergy Outside Legal	24,364	
Cities Proceeding Costs	6,140	
Estimated Amount Related to Opt-Out	$ 76,668	$ 64 32
Include 50% in One Time Charge	$ 38,334	$ 32 16

Non-Standard Digital Meter

	unit price	units	sub-total
refurbish a 1P or 3P meter	$ 5.50	1 00	$ 5 50
replace cover	$ 2 50	1 00	$ 2 50
shipping	$ 0.45	1 00	$ 0 45
shipping preparations (loaded payroll)*	$ 27 08	0 10	$ 2 71
		Total	**$ 11.16**

*ETI Payroll Loader Rate (2017 non-exempt) 0 354

OPT-OUT RATE

0 25%

ENTERGY SERVICES, INC.
ADVANCED METERING SYSTEM
NON-STANDARD METERING SERVICE RATE DEVELOPMENT
MONTHLY CHARGE REVENUE REQUIREMENT

OpCo	Monthly Meter Reads	Analysts	Rate Case Expense	Total
ETI	$ 27 33	1 49	0 89	$ 29 71

Opt Out Customers #	Total Meters	Reference
ETI	476,842	1,192

Meter Reading Trip Charges	# Months	Unit of Measurement	Charge
ETI	1	Each	$ 27 33

Back Office	Annual Salary	# Additional Employees # Additional Employees	Unit of Measurement	Payroll Loader	Total Annual Salary	Allocation to ETI*
Clerk – Specialty, Sr	$ 42,000	2	Each	67%	$ 140,414	15 15%

Rate Case Expenses	
Estimated Amount	$ 76,668
Allocated Amount (50%)	$ 38,334
Amortization Period	36
Monthly	1,064 84
No of Opt Out Customers	1,192
Amount per customer per month	$ 0 89

OPT-OUT RATE
0 25%

**ESI Billing Method Number of Customers*

ENTERGY TEXAS, INC.
ADVANCED METERING SYSTEM
NON-STANDARD METERING SERVICE RATE DEVELOPMENT
TRIP FEE CALCULATION

Monthly Trip Fee

A	B	C (1)	D	E	F	G	H	I (2) (3)	J	K	L
Entergy - Texas	Job Mix	Vehicle Rate ($/Minutes)	Travel Time (Minutes)	Transportation Costs ($)	Direct Site Time (Minutes)	Direct Clerical Time (Minutes)	Total Time (Minutes)	Wage Rate ($/Hour)	Labor Costs	Total Cost	Fee Charge
Formula for Calculations	%			CxD			D+F+G		(I/60)xH	E+J	KxB
Service personnel	100%	0 450	18 5	$8 33	5		23.5	$ 36 62	$ 14 34	$ 22 67	$22 67

Payroll Overhead (straight time) 32 50% $4 66

Total Monthly Trip Charge $27.33

One Time Trip Fee

A	B	C (1)	D	E	F	G	H	I (2) (3)	J	K	L
Entergy - Texas	Job Mix	Vehicle Rate ($/Minutes)	Travel Time (Minutes)	Transportation Costs ($)	Direct Site Time (Minutes)	Direct Clerical Time (Minutes)	Total Time (Minutes)	Wage Rate ($/Hour)	Labor Costs	Total Cost	Fee Charge
Formula for Calculations	%			CxD			D+F+G		(I/60)xH	E+J	KxB
Service personnel	100%	0 450	18 5	$8 33	30		48 5	$ 36 62	$ 29 60	$ 37 93	$37 93

Payroll Overhead (straight time) 32 50% $9 62

One-Time Trip Charge $47.55

Notes:
(1) Vehicle Rate is based on current rates of $27 06 per hours for a service vehicle
(2) Wage Rate is current rate per bargaining contract
(3) Payroll overhead is based on current rates for fully loaded payroll costs per Accounting, (Non-Exempt Payroll Loader Rates 2017)

SECTION III RATE SCHEDULES

ENTERGY TEXAS, INC. ELECTRIC SERVICE SCHEDULE MES	Sheet No.: 45 Effective Date: ~~4-1-14~~ 1-2-18 Revision No.: ~~8~~9 Supersedes: MES Effective ~~6-30-12~~4-1-14 Schedule Consists of: ~~One~~ Two Sheets

MISCELLANEOUS ELECTRIC SERVICE CHARGES

I. **APPLICABILITY**

A charge shall be assessed, or credit provided, for the activities and services listed below in accordance with the provisions and prices herein.

II. **DESCRIPTIONS**

Trip Fee

A charge of fourteen dollars ($14.00) will be made when Company is required to dispatch an employee to a customer's location.

Connection

A. Standard Metering Service C

A charge of twenty dollars ($20.00) per event will be made for those services provided in order to connect a Customer's new point of delivery to the Company's electric distribution system or to make connection changes to a Customer's existing point of delivery to the Company's electric distribution system.

B. Non-Standard Metering Service

A charge of twenty dollars ($20.00) per event will be made for those services provided in order to connect a Customer's new point of delivery to the Company's electric distribution system or to make connection changes to a Customer's existing point of delivery to the Company's electric distribution system.

Disconnect/Reconnect Fee

A charge per event will be made for those services provided in order to disconnect or reconnect a Customer's point of delivery to the Company's electric distribution system where service has been terminated or suspended due to any reason allowing for disconnection or suspension of service set forth in Company's Terms and Conditions Applicable to Electric Service. In unusual cases of abuse or tampering, Company will charge all reasonable out-of-pocket expenses necessary to restore its facilities to original condition. Service will not be reconnected until Customer pays the total amount of any funds due the Company, plus the applicable charge(s) stated below.

A. Standard Metering Service C

A charge of fifteen dollars ($15.00) per event during normal business hours will be charged to disconnect or reconnect services. The reconnection request will be deemed to have occurred during normal business hours if the Customer or other authorized party requests reconnection between 8:00 AM and 4:30 PM on a normally scheduled work day and makes payment of all billing and fees at a Company authorized payment stations by 4:30 PM of that day.

(Continued on reverse side)

A charge of thirty dollars ($30.00) will be charged to reconnect when the Customer or authorized party requests reconnection and makes payment of all billing amounts and fees at a Company authorized payment station between the hours of 4:30 PM and 7.00 PM. If full payment is made after 7:00 PM, reconnection that same day will be made only in cases of a Company-determined extreme emergency. C

B. Non-Standard Metering Service C

A charge of fifteen dollars ($15.00) per event during normal business hours will be charged to disconnect or reconnect services. The reconnection request will be deemed to have occurred during normal business hours if the Customer or other authorized party requests reconnection between 8:00 AM and 4:30 PM on a normally scheduled work day and makes payment of all billing and fees at a Company authorized payment stations by 4:30 PM of that day.

A charge of thirty dollars ($30 00) will be charged to reconnect when the Customer or authorized party requests reconnection and makes payment of all billing amounts and fees at a Company authorized payment station between the hours of 4:30 PM and 7:00 PM. If full payment is made after 7:00 PM, reconnection that same day will be made only in cases of a Company-determined extreme emergency.

Non-Sufficient Funds Charge

The Company shall charge a Non-Sufficient Funds Charge when payment by check or other payment device is not honored and returned by the Customer's financial institution, payor, holder or the holder's assignee for any reason other than bank error. The Customer shall be charged fifteen dollars ($15.00).

Temporary Metered Service Connection

A charge for temporary service connection and meter installation will be made where distribution lines are readily available and the installation of additional poles and lines is not necessary to provide service to the Customer, as follows:

- One hundred twenty-four dollars ($124) on each connection for residential construction.
- Greater of one hundred twenty-four dollars ($124) or estimated Company net costs, on each connection for other temporary service.

Where distribution lines are not readily available, or where additional poles or lines are necessary, charges will be derived based upon the Company's extension policies. Customer will be placed on appropriate Company rate schedule(s) for electric service.

Payment by Drawdraft and Levelized/Equal Payment

A one dollar ($1.00) per month credit will be provided when Customer currently authorizes drawdraft payments at the due date for services rendered by Company and the drawdraft is honored for payment in full, and the Customer also has either levelized or equal payment of billing.

Remote Meter Installation (Not available after full Advanced Meter System deployment) C

When there is (a) a threat of violence against a Company employee or contractor, or (b) a refusal to grant access to the Company's meter at the Customer's premises, or (c) a Customer request for installation of off-site meter reading, the Company will make reasonable attempts to install an Off-site Meter Reading (OMR) kWh only meter at the premises to allow off-site meter reading for any non-demand metered customer. A one-time charge of forty-two dollars ($42.00) will be made for the installation of such meter.

 (Continued on next page)

SECTION III RATE SCHEDULES

ENTERGY TEXAS, INC. ELECTRIC SERVICE SCHEDULE MES	Sheet No.: ~~45~~45A Effective Date: 4~~-~~1-~~14~~2-18 Revision No.: ~~8~~9 Supersedes: MES Effective ~~6-30-12~~4-1-14 Schedule Consists of: ~~One Sheet~~Two Sheets

MISCELLANEOUS ELECTRIC SERVICE CHARGES

Tampering Deterrent

A charge of fifty dollars ($50.00) will be made to Customers in instances of tampering with Company's meter or equipment, bypassing the same, or in other instances of diversion. This charge shall be imposed for the detection and confirmation of tampering, interfering or theft of the Company's delivery of electric service. This fee shall be paid prior to reconnection of service.

Pulse Metering Installation/Interval Data Recorder Equipment)

A one-time charge of three hundred dollars ($300) will be made to Customers for each installation of pulse metering/interval data recorder equipment. The Customer must enter into an agreement entitled Agreement and Terms and Conditions for Pulse Metering Installation. If the Customer is a participant in a load management program, the Customer must enter into an agreement entitled Agreement for Installation of Interval Data Recorder Equipment.

Meter Test Fee

A charge of thirty dollars ($30.00) will be made each time a customer requests a meter test within four years of a meter test performed at Company's expense and the subsequent meter test finds that the meter registers within the accuracy standards established by ANSI.

Non-Standard Metering Fees N

A customer receiving non-standard metering service shall be charged a one-time fee and a recurring monthly fee:

One-Time Charge for non-standard metering services

A one-time charge will be made to customers who choose to receive electric services through a non-standard meter:

1. Keep existing meter one-time charge*	$142.95
2. Digital non-communicating meter one-time charge:	
a. Before advanced meter install	$157.05
b. After advanced meter install	$204.60

**The existing meter must pass an inspection to ensure the meter is safe and meets standards for accuracy. If the existing meter fails the safety inspection or accuracy test, the customer would receive a non-communicating digital meter and be charged according to option 2a. If a customer initiates a request for non-standard metering services after an advanced meter has been installed at their premises, the only option available is No. 2b: replace the advanced meter with a digital non-communicating meter. In this case, there is an additional cost for a non-communicating digital meter and to un-install the existing advanced meter and re-install a new advanced meter after non-standard metering service is discontinued.*

(Continued on reverse side)

Monthly Charge for non-standard metering services N

A charge of $29.71 will be made each month to customers who choose to receive electric services through a non-standard meter.

III **DEFINITIONS**

A **Standard Metering Service** – Service associated with an Advanced Meter as described in PUCT Substantive Rules Applicable to Electric Service Providers.

B. **Non-Standard Metering Service** – Service associated with a meter that does not function as an Advanced Meter.

ENTERGY TEXAS, INC. ELECTRIC SERVICE SCHEDULE MES	Sheet No.: 45 Effective Date: 1-2-18 Revision No.: 9 Supersedes: MES Effective 4-1-14 Schedule Consists of: Two Sheets

MISCELLANEOUS ELECTRIC SERVICE CHARGES

I. APPLICABILITY

A charge shall be assessed, or credit provided, for the activities and services listed below in accordance with the provisions and prices herein.

II. DESCRIPTIONS

Trip Fee

A charge of fourteen dollars ($14.00) will be made when Company is required to dispatch an employee to a customer's location.

Connection

A. Standard Metering Service C

A charge of twenty dollars ($20.00) per event will be made for those services provided in order to connect a Customer's new point of delivery to the Company's electric distribution system or to make connection changes to a Customer's existing point of delivery to the Company's electric distribution system.

B. Non-Standard Metering Service

A charge of twenty dollars ($20.00) per event will be made for those services provided in order to connect a Customer's new point of delivery to the Company's electric distribution system or to make connection changes to a Customer's existing point of delivery to the Company's electric distribution system.

Disconnect/Reconnect Fee

A charge per event will be made for those services provided in order to disconnect or reconnect a Customer's point of delivery to the Company's electric distribution system where service has been terminated or suspended due to any reason allowing for disconnection or suspension of service set forth in Company's Terms and Conditions Applicable to Electric Service. In unusual cases of abuse or tampering, Company will charge all reasonable out-of-pocket expenses necessary to restore its facilities to original condition. Service will not be reconnected until Customer pays the total amount of any funds due the Company, plus the applicable charge(s) stated below.

A. Standard Metering Service C

A charge of fifteen dollars ($15.00) per event during normal business hours will be charged to disconnect or reconnect services. The reconnection request will be deemed to have occurred during normal business hours if the Customer or other authorized party requests reconnection between 8:00 AM and 4:30 PM on a normally scheduled work day and makes payment of all billing and fees at a Company authorized payment stations by 4:30 PM of that day.

(Continued on reverse side)

A charge of thirty dollars ($30.00) will be charged to reconnect when the Customer or authorized party requests reconnection and makes payment of all billing amounts and fees at a Company authorized payment station between the hours of 4:30 PM and 7:00 PM. If full payment is made after 7:00 PM, reconnection that same day will be made only in cases of a Company-determined extreme emergency. C

B. Non-Standard Metering Service C

A charge of fifteen dollars ($15.00) per event during normal business hours will be charged to disconnect or reconnect services. The reconnection request will be deemed to have occurred during normal business hours if the Customer or other authorized party requests reconnection between 8:00 AM and 4:30 PM on a normally scheduled work day and makes payment of all billing and fees at a Company authorized payment stations by 4:30 PM of that day.

A charge of thirty dollars ($30.00) will be charged to reconnect when the Customer or authorized party requests reconnection and makes payment of all billing amounts and fees at a Company authorized payment station between the hours of 4:30 PM and 7:00 PM. If full payment is made after 7:00 PM, reconnection that same day will be made only in cases of a Company-determined extreme emergency.

Non-Sufficient Funds Charge

The Company shall charge a Non-Sufficient Funds Charge when payment by check or other payment device is not honored and returned by the Customer's financial institution, payor, holder or the holder's assignee for any reason other than bank error. The Customer shall be charged fifteen dollars ($15.00).

Temporary Metered Service Connection

A charge for temporary service connection and meter installation will be made where distribution lines are readily available and the installation of additional poles and lines is not necessary to provide service to the Customer, as follows:

- One hundred twenty-four dollars ($124) on each connection for residential construction.
- Greater of one hundred twenty-four dollars ($124) or estimated Company net costs, on each connection for other temporary service.

Where distribution lines are not readily available, or where additional poles or lines are necessary, charges will be derived based upon the Company's extension policies. Customer will be placed on appropriate Company rate schedule(s) for electric service.

Payment by Drawdraft and Levelized/Equal Payment

A one dollar ($1.00) per month credit will be provided when Customer currently authorizes drawdraft payments at the due date for services rendered by Company and the drawdraft is honored for payment in full, and the Customer also has either levelized or equal payment of billing.

Remote Meter Installation (Not available after full Advanced Meter System deployment) C

When there is (a) a threat of violence against a Company employee or contractor, or (b) a refusal to grant access to the Company's meter at the Customer's premises, or (c) a Customer request for installation of off-site meter reading, the Company will make reasonable attempts to install an Off-site Meter Reading (OMR) kWh only meter at the premises to allow off-site meter reading for any non-demand metered customer. A one-time charge of forty-two dollars ($42.00) will be made for the installation of such meter.

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SECTION III RATE SCHEDULES Page 23.3

ENTERGY TEXAS, INC. ELECTRIC SERVICE SCHEDULE MES	Sheet No.: 45A Effective Date: 1-2-18 Revision No.: 9 Supersedes: MES Effective 4-1-14 Schedule Consists of: Two Sheets

MISCELLANEOUS ELECTRIC SERVICE CHARGES

Tampering Deterrent

A charge of fifty dollars ($50.00) will be made to Customers in instances of tampering with Company's meter or equipment, bypassing the same, or in other instances of diversion. This charge shall be imposed for the detection and confirmation of tampering, interfering or theft of the Company's delivery of electric service. This fee shall be paid prior to reconnection of service.

Pulse Metering Installation/Interval Data Recorder Equipment)

A one-time charge of three hundred dollars ($300) will be made to Customers for each installation of pulse metering/interval data recorder equipment. The Customer must enter into an agreement entitled Agreement and Terms and Conditions for Pulse Metering Installation. If the Customer is a participant in a load management program, the Customer must enter into an agreement entitled Agreement for Installation of Interval Data Recorder Equipment.

Meter Test Fee

A charge of thirty dollars ($30.00) will be made each time a customer requests a meter test within four years of a meter test performed at Company's expense and the subsequent meter test finds that the meter registers within the accuracy standards established by ANSI.

Non-Standard Metering Fees N

A customer receiving non-standard metering service shall be charged a one-time fee and a recurring monthly fee:

One-Time Charge for non-standard metering services

A one-time charge will be made to customers who choose to receive electric services through a non-standard meter:

1. Keep existing meter one-time charge* $142.95
2. Digital non-communicating meter one-time charge:
   a. Before advanced meter install $157.05
   b. After advanced meter install $204.60

**The existing meter must pass an inspection to ensure the meter is safe and meets standards for accuracy. If the existing meter fails the safety inspection or accuracy test, the customer would receive a non-communicating digital meter and be charged according to option 2a. If a customer initiates a request for non-standard metering services after an advanced meter has been installed at their premises, the only option available is No. 2b: replace the advanced meter with a digital non-communicating meter. In this case, there is an additional cost for a non-communicating digital meter and to un-install the existing advanced meter and re-install a new advanced meter after non-standard metering service is discontinued.*

(Continued on reverse side)

Monthly Charge for non-standard metering services N

A charge of $29.71 will be made each month to customers who choose to receive electric services through a non-standard meter.

III. **DEFINITIONS**

A. **Standard Metering Service** – Service associated with an Advanced Meter as described in PUCT Substantive Rules Applicable to Electric Service Providers.

B. **Non-Standard Metering Service** – Service associated with a meter that does not function as an Advanced Meter.

PUCT DOCKET NO. _____

APPLICATION OF ENTERGY	§	
TEXAS, INC. FOR APPROVAL OF	§	**PUBLIC UTILITY COMMISSION**
ADVANCED METERING SYSTEM	§	
(AMS) DEPLOYMENT PLAN, AMS	§	**OF**
SURCHARGE, AND NON-	§	
STANDARD METERING SERVICE	§	**TEXAS**
FEES	§	

DIRECT TESTIMONY

OF

RODNEY W. GRIFFITH

ON BEHALF OF

ENTERGY TEXAS, INC.

JULY 2017

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EXHIBITS

I. QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Rodney W. Griffith. I am employed by Entergy Services, Inc. ("ESI")[1] as Director, Advanced Metering Infrastructure ("AMI") Implementation. My business address is 9425 Pinecroft Dr., The Woodlands, Texas 77380.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying before the Public Utility Commission of Texas ("PUCT" or the "Commission") on behalf of Entergy Texas, Inc. ("ETI" or the "Company").

Q3. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL, PROFESSIONAL, AND BUSINESS EXPERIENCE.

A. I have a Bachelor of Science degree in Electrical Engineering from Lamar University. I have certificates for Managing for Execution, High Performance Leadership, and Leading Change from Cornell University. I am a registered professional engineer in the State of Texas. I am a member of the Institute of Electrical and Electronics Engineers.

I began my career in 1974 as a Co-op Engineer at Gulf States Utilities Company ("GSU"), working there until graduation. In 1978, I joined Texas

[1] ESI is a subsidiary of Entergy Corporation that provides technical and administrative services to all of the Entergy Operating Companies ("EOCs"), which include Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc. ("ETI").

Eastman Chemical Company as an Instrument Engineer. In 1979, I returned to GSU. Since that time, I have held numerous roles and assignments with GSU, which was subsequently acquired by Entergy Corporation in the early 1990s, within the Transmission and Distribution organizations in the Engineering and Operations functions.[2]

Most of my roles and assignments have involved the support and/or deployment of distribution and transmission technology. For example, in 2004, I began leading the Supervisory Control and Data Acquisition ("SCADA") Group's 11 Distribution and Transmission Controls Centers as the Manager, SCADA Systems Support. In 2007, my title changed to Manager, EMS Support Management, and my leadership role expanded to include SCADA support at the System Operation Center in addition to the 11 other Control Centers. In 2008, I became the Manager, Transmission Operations Process Control, and my responsibilities expanded to include oversight of all Operations Information Technology ("IT") support for all 12 Control Centers.

In 2012, I assumed the role of Manager, Engineering where I led the Distribution Engineering work group for ETI. In 2014, I became Manager, Compliance Systems Support, which included responsibility for business process assessment and support and the preparation of a Technology Roadmap for the distribution function. In this role, I also began leading the preliminary efforts related to AMI. In 2015, I was named Director, AMI Implementation, where I

[2] In 1998 I managed the Texas Service Quality Assessment Project, which resulted from the Commission's Order on Rehearing in Docket No. 18249.

lead the implementation of AMI and supporting systems. A list of my prior testimony is attached as Exhibit RWG-1.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q4. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony describes the technical aspects of ETI's current plan to replace almost all of its existing electromechanical (*i.e.,* analog) and digital retail electric meters with advanced meters that enable two-way data communication,[3] to design and build a secure and reliable communications network that supports two-way data communication, and to implement supporting systems, including a Meter Data Management System ("MDMS"). Those three primary components (advanced meters, the communications network, and MDMS) are commonly referred to as AMI.[4] The Company also plans to update its legacy Outage Management System ("OMS") and implement a new Distribution Management System ("DMS") to enhance overall system performance, which will be capable of utilizing the additional data provided by AMI. I also discuss how ETI plans to integrate the MDMS, OMS, and DMS with an Enterprise Service Bus ("ESB") and legacy IT systems. All together, these components make up an Advanced Metering System ("AMS").

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3 The deployment plan does not include meter replacement for customer accounts that receive service at transmission voltage.

4 For example, the U.S. Department of Energy defines advanced metering infrastructure as "an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers." *See* https://www.smartgrid.gov/recovery_act/deployment_status/sdgp_ami_systems.html.

In my testimony I describe the individual components of the AMS deployment and the approach taken by ESI on behalf of ETI to identify, evaluate, and select vendors for the: (1) advanced meters, (2) communication system, (3) MDMS, and (4) system integration. I also describe ETI's approach to implement the various AMS components and the planned deployment schedule. I describe how the data that is collected, stored, and transmitted by the advanced meters will be protected with administrative, physical, and technological safeguards at various stages of the deployment. Finally, I discuss the capital and operations and maintenance ("O&M") costs associated with the Company's AMS deployment.

Q5. PLEASE SUMMARIZE ETI'S AMS DEPLOYMENT PLAN.

A. ETI is developing a design and implementation plan to implement a comprehensive AMS, which will be comprised of industry-accepted technology and equipment. The Company followed a rigorous approach to identify, evaluate, and select experienced vendors and also negotiate fair contracts with commercial terms protecting the interests of the Company and its customers. The selected technology and vendors have a proven track record of success for large AMS implementations at other utilities throughout the United States and globally. Additionally, as part of its AMS implementation, ETI is updating the existing OMS and implementing a new DMS to enhance utility operations and provide an overall more reliable distribution system where service can be restored faster and more efficiently after customer outages.

The Company has planned a deployment schedule reflecting the complex interrelationships between various IT systems and managing the normal risks associated with a large-scale meter deployment.

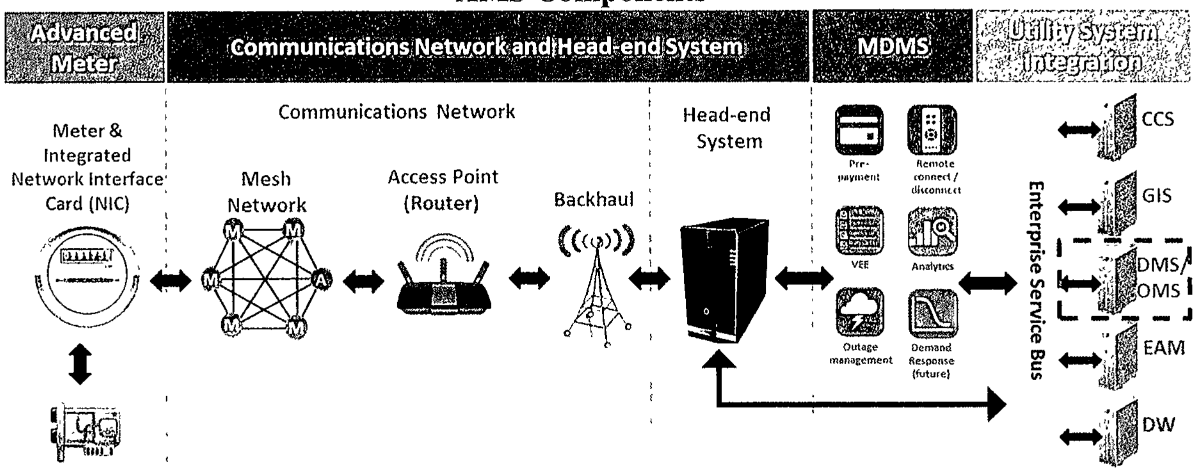
Finally, ETI has established a comprehensive cost estimate for the design and deployment of the AMS, incorporating vendor cost information from a competitive bidding process, internal Company costs associated with executing the AMS project control environment, and an appropriate and reasonable contingency. The contingency addresses the possibility of risks that naturally may arise from a large and complex project such as the AMS deployment. The Company's approach to estimating AMS costs is reasonable and consistent with the approach used for other large capital programs.

III. ADVANCED METERING SYSTEM

Q6. PLEASE PROVIDE AN OVERVIEW OF THE COMPONENTS OF THE COMPANY'S AMS DEPLOYMENT.

A. The components of the AMS deployment consist of: (1) advanced electric meters; (2) a communication system, comprised of a network interface card ("NIC") that will be installed in the advanced meter, a communications network, and a head-end system; (3) an MDMS; (4) an update of the legacy OMS; and (5) the implementation of a new DMS. Finally, all of these components will be integrated into existing and planned IT applications and other systems via an ESB. The components are illustrated in Figure 1 below.

Figure 1
AMS Components



Q7. WHAT CAPABILITIES WILL BE INCLUDED WITH THE COMPANY'S PROPOSED AMS DEPLOYMENT?

A. The AMS will be designed and built to deliver a number of functionalities and operational applications (commonly referred to as "use cases" or "applications") immediately upon deployment, as well as to support additional applications that may be implemented over time. The applications that will be available immediately upon deployment and meter activation include: 1) automated remote meter reading, including recording and processing interval consumption data at 15-minute intervals for residential customers and 5-minute intervals for commercial and industrial customers,[5] with the verified data being made available

[5] *See* 16 Tex. Admin. Code ("TAC") § 25.130(g)(1)(A) and (G). In his Direct Testimony, Company witness Jay A. Lewis describes the requirements of a Deployment Plan for implementing an AMS consistent with Texas statutes and Commission rules and how the Company's Application, including its accompanying testimony and exhibits, provide all information required by the statutes and rules.

to customers daily;[6] 2) two-way communications;[7] 3) remote enabled service connection, disconnection and reconnection;[8] 4) remote configuration and firmware upgrades;[9] 5) automated meter health and status communication; 6) web-based customer data accessibility, which will facilitate customers' web portal access of their usage information;[10] 7) customer usage goal-setting thresholds and alerts; 8) outage management support, including restoration verification; 9) theft and tamper notifications to the Company; 10) event and load profiling for analytics; 11) power quality reporting; 12) asset mapping and predictive asset management; 13) more accessible information for load forecasting and load research efforts; 14) support for implementation of pre-pay programs; 15) ability to incorporate distributed energy resources ("DERs"), which have grown more prevalent in recent years (*e.g.,* rooftop solar systems); 16) the capability to time-stamp meter data;[11] and 17) the capability to communicate with devices inside the premises based on open standards and protocols that comply with nationally recognized non-proprietary standards.[12]

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6 *See* 16 TAC § 25.130(g)(1)(E).

7 *Id.* at 25.130(g)(1)(B).

8 *Id.* at 25.130(g)(1)(C). Note that loads that currently have poly-phase, class 200 (200 amp rating) meters, which includes commercial customers and some residential customers, will not have a service switch until a poly-phase meter with those devices become available in the market. In its Deployment Plan, the Company seeks a waiver of this requirement. Further, all meters rated above 200 amps will not have a service switch.

9 *Id.* at 25.130(g)(1)(K).

10 *Id.* at 25.130(g)(1)(E).

11 *Id.* at 25.130(g)(1)(D).

12 *Id.* at 25.130(g)(1)(J).

Q8. WILL THE COMPANY'S AMS INCLUDE FUNCTIONALITIES THAT CAN SUPPORT ADDITIONAL APPLICATIONS AND PROVIDE FUTURE CUSTOMER BENEFITS?

A. Yes. The AMS will support additional applications that may be implemented over time. Those applications include features such as: 1) advanced usage analytics and energy savings tips that are customized to each unique customer; 2) dynamic pricing programs such as time-of-use ("TOU") and real-time pricing;[13] 3) more expansive demand response ("DR") programs; 4) potential control and dispatch of DERs; 5) streetlight monitoring and control applications; 6) voltage optimization and control (*e.g.*, conservation voltage reduction or "CVR" programs); 7) enablement of additional distribution automation; and 8) enablement of distributed intelligence.[14] These additional functions and applications are not included in ETI's AMS deployment, and each application will require some level of additional investment in order to achieve the described functionality.

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[13] *Id.* at 25.130(g)(1)(F).

[14] In the AMS project context, distributed intelligence is the ability to perform analytics at the edge of the grid to support true real-time control of grid devices without having to send information back through the head-end into utility systems for processing and decision making. In the future, the addition of DERs, electric vehicles ("EVs"), and microgrids would be expected to increase the amount of data that the AMS solution will be required to transfer and process to ensure reliability and efficient grid operations.

IV. OVERVIEW OF ETI'S APPROACH TO IMPLEMENT AN AMS

Q9. WHAT STEPS WILL THE COMPANY IMPLEMENT TO MANAGE THE AMS DEPLOYMENT?

A. The AMS deployment is a large capital program that will be managed in compliance with ETI's capital project management structure and control environment. At the outset of the program, ESI, in conjunction with ETI, established a Project Management Office ("PMO") structure for the AMS project to manage the program design, vendor selection, and AMS deployment. The PMO is a matrix organization that consists of multiple work teams, each of which is focused on specific functional areas and project execution activities.

The PMO is governed by an Executive Steering Committee that consists of representatives from each of the participating EOCs, including ETI (the "AMS Steering Committee"). The AMS Steering Committee is responsible for oversight and approval of PMO activities. ETI's participation on the AMS Steering Committee includes ETI's Vice President, Customer Service, Company witness Mr. Vernon Pierce or ETI representatives acting at his direction. These ETI representatives not only participate in the decision-making for the project but also provide direct guidance and input to the PMO on issues specific to or otherwise affecting ETI's AMS deployment. For example, although Mr. Pierce can directly address this, I am generally aware that the selected vendors I discuss later reflect ETI's preferred selections. In addition, I have worked with ETI representatives to review the various PUCT requirements that in turn will help drive the design phase of ETI's AMS deployment.

A similar PMO approach has been used to manage and report on project performance parameters (*e.g.*, cost, schedule, scope, supply chain, risks, safety, and quality) for other large-scale utility projects. The Company's PMO approach and associated control environment are reasonable and appropriate for a project such as an AMS.

Q10. WHAT IS YOUR ROLE IN THE PMO?

A. I am the PMO lead for the AMS implementation. My responsibilities include overseeing the PMO activities and communications, managing the overall PMO logistics, resolving cross-functional issues across program work teams, and functioning as the point of accountability for the overall program implementation success.

Q11. WHAT IS THE EXPECTED SCHEDULE FOR THE AMS DESIGN AND DEPLOYMENT?

A. Preliminary design work began in 2016 and includes the results of a review of relevant PUCT rules in order to incorporate any specific requirements. The initial design work will be followed by the development of detailed IT functional requirements, system build, testing, and the eventual deployment of advanced meters. Assuming PUCT approval is received in 2017 or early 2018, the communications network deployment is expected to begin by late 2018. Under the current expected schedule, the deployment and installation of the advanced meters at customers' premises would begin in early 2019 and take approximately three years to complete. Table 1 below shows ETI's preliminary meter deployment schedule using approximate meter numbers. A more specific schedule, including geographical areas, is expected to be available by the end of 2017.

Table 1

Preliminary Deployment Schedule			
	2019	2020	2021
Electric Meters	166,000	204,000	107,000

Q12. CAN YOU ELABORATE ON WHY IT IS EXPECTED TO TAKE SEVERAL YEARS FOR ETI TO FULLY DEPLOY AN AMS?

A. As illustrated above, deployment of an AMS includes significantly more than just replacing existing meters with advanced meters, which in itself is a time-consuming undertaking. It is necessary to first build the IT systems, which involves the development of detailed AMS business requirements, the deployment of software and hardware, and the integration of new and upgraded systems with existing Company applications estimated to involve approximately 150 interfaces between 15-20 different IT systems. Once the basic IT infrastructure is installed, the systems must be integrated and tested, and employees must be trained to confirm the AMS operates as expected and achieves its functional objectives. The next step is building the communications system that allows the IT systems to communicate with the advanced meters. That step involves installation of an estimated 310 access points and 2,100 repeaters, followed by testing communications from those points to the head-end system. The final step is replacing customers' existing meters with new advanced meters and optimizing the communications network. For ETI, it is estimated that approximately 166,000 meters will be replaced in 2019, 204,000 meters in 2020, and then finally 107,000 meters in 2021.

The Company believes that a three-year period for installing the advanced meters is appropriate. This time frame provides a reasonable balance between timely meter installation and efficient, cost-effective supply chain and installation crew management. The sequence of the deployment will also allow ETI and its customers to realize the benefits of advanced meters as they are deployed rather than wait until a later date. In other words, the communications network will be functional prior to the installation of meters, thereby enabling the remote communication functionality of the advanced meters and its associated benefits as early as the point of meter installation. Additionally, attempts to expedite deployment schedules can reasonably be expected to significantly increase installation costs due to the increased coordination and oversight that is needed, increased labor and overhead costs, and heightened pressures on the meter manufacturing and delivery processes. Similarly, ETI would expect expedited installation deployments to result in less effective training for field installers, which in turn can be expected to lead to less efficient installations and dissatisfied customers. Accordingly, ETI is targeting a three-year deployment, beginning in 2019.

Q13. ARE OTHER ENTERGY OPERATING COMPANIES PLANNING TO DEPLOY AN AMS AT THE SAME TIME AS ETI?

A. Yes. There are common components of the AMS that can be shared and will allow for contemporaneous deployment of an AMS across various EOC service areas, including much of the IT systems and portions of the communications network. This timing of the various deployments and use of common components provides opportunities for economies of scale and lower overall costs for customers. For example:

- There will be one head-end system integrated into the existing and planned IT systems. This approach saves both time and expense compared to the alternative of ETI potentially purchasing a separate head-end system and integrating it with the IT systems at separate times. For example, the head-end system is estimated to cost $26 million, and of that amount, ETI's share is expected to be $4 million.
- There are volume discounts for field communications devices and advanced meter purchases. As a result, collectively contracting to purchase and install AMS technology results in lower costs than would be achieved if ETI separately purchased and installed an AMS independently of the other EOCs at different times.
- A coordinated deployment leads to increased economies of scale for installation of field communication devices and advanced meters, as well as for associated vendor training, management, and oversight costs.
- Additional efficiencies can be realized from integrating billing systems with the AMS at the same time.

V. THE AMS PROCUREMENT PROCESS AND COMPONENTS

Q14. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I will discuss in greater detail the major components of the Company's proposed AMS deployment, beginning with a discussion of the competitive solicitation through Requests for Proposals ("RFPs") and the contracting process utilized by the Company for the procurement of four key AMS components: (1) the advanced meters and installation; (2) the communications network; (3) the MDMS; and (4) system integration.

A. RFP and Contracting Process

Q15. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S VENDOR SELECTION AND CONTRACTING PROCESS.

A. Vendor selection for four of the AMS components was conducted by a team comprised of representatives from ETI, ESI, and the other EOCs. The selection team performed a rigorous, comprehensive, and competitive vendor selection process to identify, attract, and contract with experienced and competent AMS equipment and service providers. The selection team followed the Company's standard vendor selection process for large capital programs, which included initial market research; a competitive RFP process; detailed bid evaluation; oral presentations from selected vendors; and a detailed contract negotiation process to establish clear and fair commercial terms and vendor performance expectations. Throughout the vendor selection process, the selection team relied on the

PowerAdvocate Sourcing Intelligence website ("PowerAdvocate") to control and manage all communication between the selection team and potential vendors.

Q16. WHEN DID THE COMPANY BEGIN THE RFP PROCESS?

A. On June 26, 2015, the Company, through ESI, issued four separate RFPs for (1) the advanced meters and installation; (2) the communications network; (3) the MDMS; and (4) system integration. Each of the RFPs identified the applications needed to achieve the benefits for ETI customers. The RFPs also specified the functional and technical requirements necessary to execute these applications. These requirements were based on what the Company believes to be generally-accepted industry standards and commercially proven technologies, which was evidenced by the many responses to the RFP and willingness of vendors to meet these requirements. On August 21, 2015, approximately 30 responses from 20 individual vendors were received. Some vendors submitted bids for more than one RFP.

Q17. HOW WERE THE RESPONSES EVALUATED?

A. Consistent with Company practices for procurements in large capital programs, technical and commercial evaluations of each RFP bid were run in parallel by two evaluation teams. The commercial evaluations were performed by the Supply Chain Group, and the technical evaluations were performed by various subject matter experts, including members of the AMS project team and ETI's Senior Manager of Operations and Safety. Each evaluation team was comprised of subject matter experts across a variety of areas, including IT and engineering. Recommendations were approved by the AMS Steering Committee.

The technical and commercial evaluations were kept separate, which eliminated the risk that the technical evaluators would be influenced by cost considerations. The evaluation teams scored the bids on dozens of technical criteria, including ranking the functional capabilities of the products and/or services as well as the vendors' previous experience deploying them. The composite scores were used to identify which bids best met the requirements as defined in the RFPs. Those initial bids were narrowed by the technical evaluation team to a shortlist of vendors who were recommended to the AMS Steering Committee for approval.

Following approval of the shortlist, the selected vendors were invited to participate in the next round of the RFP process. During this round, the technical teams conducted a series of all-day meetings with individual vendors. The selected vendors were encouraged to present their best products and/or services and given opportunities through explanation and questioning to clarify their bids during these meetings. Following that process, the technical evaluation teams re-evaluated vendor scores based upon clarifications provided during the vendor meetings and identified the top two vendors from each RFP. These top vendors were then presented to the AMS Steering Committee for approval to begin contract negotiations. Next, the Supply Chain Group, supported by the PMO, engaged in contract negotiations with these top bidder(s) in each of the four RFPs. During those negotiations, Supply Chain reported to the AMS Steering

Committee, which provided feedback and approval during the negotiations process.

Q18. UPON WHAT CRITERIA WERE THE BIDS EVALUATED?

A. The evaluation teams scored each bid on dozens of technical criteria. The criteria measured the quality of the bids in the following broad areas: (1) capability of the technical product and/or service; (2) ability of the product and/or service to support the desired functional and technical requirements; (3) scope of services offered; (4) experience of the bidder and their proposed team members on AMS projects at peer utilities; and (5) other general considerations, such as the bidder's current financial standing and general understanding of the products or services solicited in the RFP.

Q19. HAS THE COMPANY EXECUTED CONTRACTS WITH THE SELECTED BIDDERS?

A. Yes. I identify the selected vendors and the rationale for their selection in the following section of my testimony. The executed contracts are included in HSPM Exhibit RWG-4.

Q20. PLEASE DESCRIBE THE KEY FEATURES OF THE CONTRACTS.

A. The contracts are designed with an end-to-end solution to achieve cost certainty. In other words, the contracts specify pricing for the products and services for every phase of the project, from design through deployment. Equipment and software prices are not expected to change. Implementation costs, on the other hand, are fixed based on the anticipated scope and timing of the deployment, which is currently in the design phase. Accordingly, adjustments to scope may be required following completion of the design phase. However, any proposed changes that would increase project costs by more than 10 percent of the contract price would require certain internal approvals.

The contracts also entitle the Company to purchase the meter, communications and supporting software technology that are available at the time of deployment. In other words, the advanced meters and communications network that are installed will be the current technology in 2019 (as opposed to 2016 technology), but the maximum price (subject to adjustment for changes in the Purchase Price Index in certain circumstances) for those products has been fixed in the contract.

Additional features of the contracts intended to enhance cost certainty, mitigate risk, and increase flexibility include the points outlined below. The specific features of each contract will vary depending on the type of products, software and services involved:

- Wherever practicable, vendor payments are tied to the delivery of products and/or the completion of project milestones. Importantly, meters and network equipment, and associated installation charges, will not be billed to the Company until they are installed and functioning. Vendors therefore have an incentive to complete their work on time.
- A portion of vendor service charges are subject to holdbacks and potential credits if key performance indicators ("KPIs") are not satisfied.

Depending on the type of work involved, the KPIs may include metrics relating to timeliness, work quality, safety, and diversity.

- Additionally, liquidated damages may be imposed if a vendor is late in delivering products.

Q21. HOW WILL THE CONTRACTS BE COORDINATED AND MANAGED?

A. A cross-project governance framework will be used to coordinate and manage all vendor interactions and dependencies. In addition, the PMO and ESI's Supply Chain will manage contract implementation and performance of the vendors for all related contracts. A dedicated ESI contract manager will have oversight of these activities, with the PMO and/or ESI's Supply Chain seeking AMS Steering Committee approval for any material changes in scope.

Q22. HAS THE COMPANY EXECUTED CONTRACTS FOR THE DMS AND OMS COMPONENTS OF THE AMS?

A. Yes. The Company executed contracts with its current vendor of related systems, *i.e.*, SCADA, for the DMS and OMS products as well as integrating and/or upgrading legacy systems. The executed contracts are included in HSPM Exhibit RWG-4. As discussed later, the current vendor is familiar with the legacy SCADA systems, which will provide for an efficient system integration, and the Company already owns the license for DMS software, which avoids costs compared to acquiring a different product from a new vendor. The Company is still negotiating contracts for related DMS/OMS services, including system integration, business readiness, and technical services.

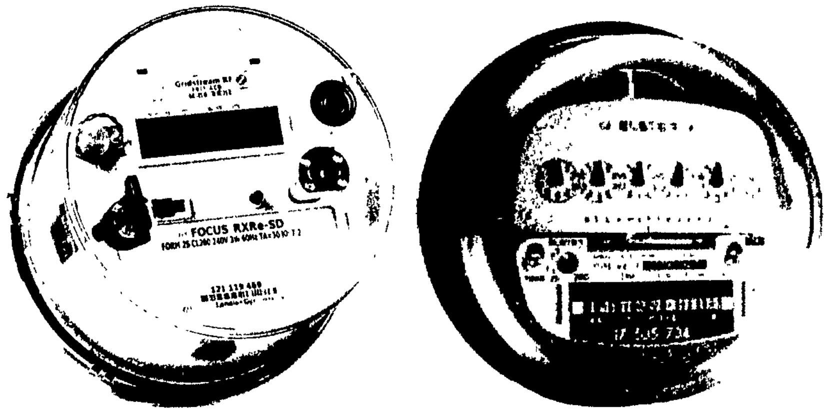
B. AMS Components

1. Advanced Electric Meters

Q23. WHAT IS AN ADVANCED ELECTRIC METER?

A. An advanced electric meter is similar in appearance and purpose to the traditional analog and digital meters used today for recording energy usage at customers' premises. However, the advanced meter measures, records, and transmits both the register reading and time-differentiated energy usage information, as well as other information like power outage, power restoration, voltage, and meter alarms to the Company through a NIC. The Company can also send signals and commands to the advanced meter for reasons such as checking its status, upgrading firmware, or remotely connecting or disconnecting service. Traditional analog and digital electric meters, on the other hand, lack communications capabilities. These traditional meters must be read manually by a meter reader, cannot remotely provide time-differentiated energy usage information, provide no remote indication of power status or voltage information, cannot receive commands or report alarms, and cannot be used to remotely connect or disconnect service.

Figure 2
A modern, advanced electric meter (left)
and an older, analog meter (right)



Q24. WHAT VENDORS DID THE COMPANY SELECT FOR ADVANCED METERS?

A. In order to mitigate single-sourcing meter vendor risks, and consistent with the experience of peer utilities that have previously deployed advanced meters, the AMS Steering Committee approved a dual-source meter vendor strategy. As a result of the RFP process described above, Elster Solutions, LLC, a Honeywell Company ("Elster") was selected to be the primary vendor for the advanced electric meters, with Landis+Gyr Technology, Inc. ("Landis+Gyr") as the secondary vendor. Additionally, Elster was selected as the vendor responsible for meter installation.

Q25. WHAT IS THE DISTINCTION BETWEEN BEING A PRIMARY VERSUS SECONDARY VENDOR?

A. The distinction between primary and secondary vendors is the anticipated volume of advanced meters supplied. It is anticipated that the Company will purchase a substantial majority of the advanced meters from the primary vendor. By supplying a substantial majority of the volume, the volume pricing discounts discussed earlier are maximized with respect to the primary supplier pricing.

Q26. WHAT ARE THE RISKS ASSOCIATED WITH A SINGLE-SOURCE METER VENDOR STRATEGY?

A. In discussions with vendors and other utilities, several instances were noted where a utility chose a single-source meter vendor, and during deployment the meter vendor had manufacturing or production issues. In those circumstances, the options included: (1) delaying deployment while the single-source meter vendor caught up with production; or (2) contracting with another meter vendor, which requires significant time to negotiate the contract, design the product, and ramp up production. In that situation, contracting with another meter vendor during the deployment phase creates pricing risk. By contracting with a secondary vendor at the same time the primary meter vendor contracts are executed, such risks have been mitigated. In other words, having only a single meter vendor at the outset of the project could significantly delay deployment and increase costs. Those risks have been mitigated by contracting with a secondary meter vendor that will be involved in the AMS project from start to finish. The secondary vendor will also produce a portion of the advanced meters for ETI's AMS deployment. Should the Company's primary meter vendor become unable to meet the deployment schedule, the Company can more quickly increase reliance on its secondary meter vendor in order to avoid lengthy or costly delays and additional cost uncertainty during deployment.

Q27. WHY WERE ELSTER AND LANDIS+GYR METERS SELECTED FOR THE AMS DEPLOYMENT?

A. The Elster and Landis+Gyr meters have the functional and technical capabilities to achieve the required applications, exceeded some of the technical requirements of the RFP, and are among the lowest cost meters bid into the RFP. These meters also support the functional and technical capabilities to achieve potential future applications discussed earlier, are designed to meet or exceed applicable American National Standards Institute ("ANSI") standards,[15] and are based on safe and reliable designs from the manufacturers. Additionally, based on representations supplied by the vendors, over 100,000,000 advanced meters have been or are being deployed by these meter vendors worldwide, 43,000,000 of which are in the U.S.[16]

Some of the technical aspects of these advanced meters include that they are equipped with an on-board computational engine that provides faster

[15] *See* 16 TAC § 25.130(g)(1)(H) and (I).

[16] *Id.* at 25.130(e).

metrology; they are capable of receiving firmware and/or programming upgrades remotely and therefore can, to a certain extent, be upgraded to keep pace with technological advances; and they have the potential to support future applications to be computed and stored at the meter.

2. Communications Infrastructure

Q28. WHY IS A COMMUNICATIONS SYSTEM A NECESSARY COMPONENT OF AN AMS?

A. Without the communications system there would be no capability to communicate remotely with, or receive data from, advanced meters, which is essential to achieving the customer and operational benefits of an AMS described by Company witnesses Mr. Pierce and Jay A. Lewis. The communications network is also a critical piece of the infrastructure backbone and serves as the foundation upon which potential future integrated grid functionalities can be implemented. These future capabilities are discussed in more detail by Mr. Pierce.

Q29. PLEASE DESCRIBE THE COMMUNICATIONS INFRASTRUCTURE AND THE FUNCTIONS IT WILL PROVIDE.

A. The communications infrastructure is a system of communications components that provide for two-way data transfer – both from the meter and other AMS components to the Company and from the Company to those AMS components. For purposes of ETI's AMS deployment, the communications system includes the

NIC, a "mesh" communications network, a backhaul communications network, and the head-end system at the Company's data center.

The NIC is a modular circuit board located inside each advanced meter. It is the component that connects the advanced meter to various networks and enables remote two-way communication between the meter and the Company in a reliable and secure manner. The NIC will be procured from the communications system vendor by the meter vendor. The meter vendor will install the NIC into the meter prior to delivery and installation.

The mesh communications network is a wireless network made up of radio "nodes" that have the ability to communicate with each other. Each NIC and network component (*e.g.*, access points and relays) is a separate node in the mesh network. Meter data and messages "hop" from node-to-node until reaching a destination node, which can be a NIC, relay, or access point, depending on the direction the data is traveling. Data is communicated between the access points and the head-end system at the data center via the backhaul network, which will be a combination of cellular service and Company-owned fiber.[17] I discuss below why the Company chose a mesh network.

The head-end system refers to the hardware and software components in the data center that reliably and securely: 1) receive information from field components, including meters; 2) transmit data to those components; and 3) route

[17] There may be some limited instances where, due to the remote location of a meter or meters, the NIC inside the meter will include a cellular radio that will be used to directly access the backhaul cellular network.

meter information to appropriate internal IT systems, including the MDMS. In addition, the head-end system will contain basic data validation and error checking functionality in its role of collecting and passing data, information, and commands between various utility systems (*e.g.,* the MDMS) and field components.

Q30. WHY DID THE COMPANY CHOOSE A MESH NETWORK FOR THE AMS DEPLOYMENT?

A. A mesh network provides a number of advantages over competing technologies like direct point-to-point cellular and point-to-point wireless, including:

- The network can adapt when the physical world changes (*e.g.*, new buildings emerge) by establishing new communications paths automatically, as needed, to neighboring meters.
- Adding devices to mesh networks creates new paths through the network, improving routing options and, thus, improving network reliability.
- Mesh technology is very well-suited for supporting low-cost, low-power battery-operated devices because of its redundant communications pathways.
- Mesh nodes communicate with each other within clusters at no additional cost (much like nodes in an enterprise WiFi network do not require a "data plan" within the enterprise location), and therefore provide a lower-cost solution.
- Using the mesh technology enables increased network bandwidth and the higher demands of AMS applications.
- Mesh technology architecture incorporates well-established, historically-proven, cybersecurity standards.

Q31. WHAT VENDOR WAS SELECTED FOR THE COMMUNICATIONS NETWORK?

A. After evaluating the RFP responses and engaging in the negotiation process discussed earlier, Silver Springs Networks, Inc. ("SSN") was selected to be the vendor of the communications network.

Q32. WHY WAS SSN SELECTED FOR THE AMS DEPLOYMENT?

A. SSN is an industry leader in wireless communication networks for advanced meters. The evaluation teams scored SSN's proposal highly for having (1) best-in-class technology that provides the fastest available mesh network speeds and extremely low failure rates for its manufactured NICs; (2) experience supporting the applications the Company is deploying for this project; (3) experience supporting the applications the Company may deploy in the future, *e.g.*, distribution automation; (4) experience deploying an AMS at several other U.S. utilities with similar geography and customer classes as the Company (*e.g.*, Oklahoma Gas & Electric and City Public Service ("CPS") in San Antonio, Texas); (5) experience integrating its NICs with the selected meter manufacturers (including both Elster and Landis+Gyr); (6) experience integrating its head-end system with the leading MDMS platforms (including Accenture, the selected MDMS vendor identified below); and (7) a broad services offering, including a high-quality approach for designing the network. SSN was also willing to contractually commit to high-quality service level agreements ("SLAs") in supporting the overall AMS project, including reliable and timely meter reading, high head-end system availability, and timely outage and restoration notifications. SSN was also willing to commit to service level credits for failure to meet the performance criteria established in the SLAs.

3. MDMS

Q33. WHAT IS AN MDMS?

A. An MDMS is a sophisticated software system that collects, stores, manages, and validates meter data.[18] It also functions as the interface between other IT systems, including billing, workforce management, asset management, and outage management. In addition, it provides various reporting capabilities to support load forecasting, load research, management reporting, and customer service metrics.

Q34. HOW DOES AN MDMS ENHANCE THE FUNCTIONALITY OF AN AMS?

A. While an AMS is not required for an MDMS to provide incremental value and functionality as compared to the status quo, the MDMS is a necessary and critical component of an AMS. The MDMS will electronically collect, process, analyze, and validate granular, time-differentiated data received from the advanced meters via the head-end system; perform two-way distribution of information and commands between the head-end and other IT systems; store meter data for

[18] The MDMS performs what is known as "VEE" – validation, estimating, and editing. The VEE process serves as a check on the data. For example, if there is a communications issue, the meter will store interval data until communications are reestablished. During this "dark" period, the MDMS would use estimated data until the actual data is received later.

access and retrieval; and provide customized reports based on meter data and analytics performed. The MDMS, in conjunction with the AMS, can further serve as a platform for additional applications, *e.g.*, implementation of new products and services for customers.

Q35. WHAT MDMS VENDOR DID THE COMPANY SELECT?

A. After evaluating the RFP responses and engaging in the negotiation process discussed earlier, Accenture, LLP ("Accenture") was selected to be the vendor of the MDMS.

Q36. WHY WAS ACCENTURE SELECTED AS THE MDMS PROVIDER FOR THIS DEPLOYMENT?

A. Accenture has extensive experience with large-scale deployments at peer utilities, such as CenterPoint Energy, CPS Energy, and Alliant Energy. This experience includes integration with the Company's chosen bidder for the communications system (SSN) and the Company's existing customer billing system. The Accenture team members proposed for the project have multiple years of experience on AMS projects similar to the Company's. From an architecture perspective, Accenture's product provides pre-built adapters for integration with the Company's existing customer billing system and chosen head-end system. Accenture's product is also capable of calculating complex billing determinants required to support the Company's large commercial and industrial customers. Accenture is a leader in MDMS technology and brings a well-defined product roadmap and focused research and development investment. This focus is important as the Company considers implementing future applications beyond the initial AMS deployment, *e.g.,* dynamic pricing programs. The service delivery approach proposed by Accenture is also advantageous because it currently provides the Company with support for existing applications, including the customer billing system.

4. System Integration

Q37. PLEASE EXPLAIN THE PURPOSE OF SYSTEM INTEGRATION.

A. System integration involves integrating the various AMS components into the existing and planned IT infrastructure, resulting in a single, unified AMS. System integration will be performed by a third-party vendor (the System Integrator), who will be responsible for designing the AMS solution architecture. This includes definition of integration points between all relevant systems and the ESB, data conversions, data integrations, and data governance. System integration is necessary to help ensure that all components sought through the AMS RFPs can be combined together into a functioning single, unified AMS solution.

Outside of the system integration role, the System Integrator will be responsible for mapping, proposing, and obtaining approval from the PMO with respect to the business processes affected or created as a result of the AMS and implementation of the applications. Further, the System Integrator will provide services related to change management and business process design (*e.g.*, business readiness) to ETI so it can effectively use the AMS to deliver the intended operational and other customer benefits, both initially and into the future.

Q38. WHICH VENDOR WAS SELECTED AS THE SYSTEM INTEGRATOR?

A. The Company selected International Business Machines Corporation ("IBM") as the System Integrator for the advanced meters, communications infrastructure, and MDMS.

Q39. WHY WAS IBM SELECTED?

A. IBM is a recognized global leader in providing system integration services, including extensive experience in developing AMS and advanced grid deployment strategies. Importantly, IBM has proven experience in AMS planning and implementation, especially in the U.S. market, where IBM has provided system integration services for over half of the AMS deployments in the country. The evaluation teams gave IBM high scores for: (1) demonstrating technical systems expertise with clear strengths in implementation philosophy, methodology, cyber-security, and complex billing conditions; (2) demonstrating superior understanding of the complexities of large scale, multi-jurisdictional AMS implementations; (3) providing personnel who have significant technical experience with implementing an AMS; (4) including program accelerators that can be leveraged as starting points for key activities, which can potentially result in a more efficient deployment; (5) IBM's broad multi-jurisdictional U.S. experience, including specialization on advanced grid technologies that can complement the Company's long-term advanced grid goals discussed by Mr. Pierce; (6) providing an approach that is more structured and drives towards a standardized solution versus a highly customized one, as compared to other bids; (7) considerable recent experience with end-to-end AMS deployments; and (8) having a substantial U.S.-based presence, which reduces risk and drives efficiencies required for cost and schedule certainty.

Q40. WHAT STEPS WILL ETI TAKE TO MANAGE THE SYSTEM INTEGRATION?

A. The activities of the System Integrator will be performed in coordination with and under the oversight of the PMO.

C. DMS and OMS

Q41. WHAT ARE THE PURPOSES OF A DMS?

A. A DMS is a software platform that supports the full suite of distribution management activities and optimization of distribution operations. It provides ETI the ability to monitor and control the distribution grid through a rich, map-based user interface that includes functions to optimize and automate the execution of switching activities that facilitate outage restoration of the distribution grid.[19]

[19] Switching involves the opening and closing of electrical devices on distribution lines to isolate the problem causing an outage. In some circumstances, this can allow for power to be rerouted and restored to customers while the cause of the outage is being repaired.

Q42. HOW ARE SWITCHING ACTIVITIES MANAGED TODAY?

A. In today's operational environment, switching orders are produced to document the steps required to safely perform equipment switching. Present day processes require a series of mostly manual steps for preparation and execution of switching orders. These steps take place in several different systems and paper processes, and complex switching orders may require engineering studies to ensure safe load transfers.

Q43. HOW DOES A DMS IMPROVE THE SWITCHING PROCESS, AND WHAT ARE THE BENEFITS?

A. The DMS streamlines the switching order process by bringing all information about the distribution system, including grid connectivity and real-time power flow, into a single platform. For a given outage, the DMS will rapidly produce the most effective switching order needed to achieve restoration of service, identifying the switching steps that will restore the most customers in the shortest timeframe. This capability reduces the time that operators must spend preparing the documentation needed to manually perform safe switching of distribution equipment during outage restoration activities. The full-function simulator in the DMS can be used to observe the projected effect of any switching activities on the distribution grid, reducing the need for engineering studies on more complex switching scenarios. Importantly, these combined capabilities support faster restoration of service for ETI customers following outages. In addition, the DMS simulator can be used for training operators in outage response activities, which can also lead to faster outage restoration.

Q44. WHY IS IT IS REASONABLE TO IMPLEMENT A NEW DMS AT THIS TIME?

A. The nature and extent of the energy usage data made available to the Company through an AMS creates a new opportunity to enhance the Company's energy distribution management activities and modernize the electric grid. While the Company currently has a few separate systems that allow it to perform some distribution management functions, it does not have a modern, unified DMS. Building on the AMS technology and associated energy usage data availability, the new DMS will provide distribution operators with a modern tool designed to merge and display real-time information from substations, distribution lines, and customer meters, which provides a complete picture of what is happening on the distribution grid. Once integrated with the AMS, the DMS will provide timely information to perform asset life analytics and improve network design and operations, which can reduce costs. It will also provide the ability to better monitor assets, which aids in preventive maintenance that can extend asset life and prevent outages from occurring.

A modern DMS, in conjunction with an AMS, also lays the foundation for valuable future applications and functions like distribution automation. The automation of devices like reclosers and feeder switches, along with communicative sensors, would allow distribution operators to remotely reroute power around an outage, which can minimize the number of customers affected by an outage. Further, the ability to remotely operate distribution devices can decrease the duration of outages. Additional beneficial future applications include: fault location, isolation and restoration ("FLISR"); volt/volt-ampere reactive optimization; conservation through voltage reduction (a/k/a CVR); peak demand management; and additional support for new DERs (*e.g.,* rooftop solar systems, microgrids, and EVs).

Q45. WHAT ARE THE PURPOSES OF AN OMS?

A. An OMS is a utility distribution network management software application that models network topology for efficient field operations related to outage restoration. It assists in the detection, analysis, and restoration of service following outages. An OMS tightly integrates with call centers and advanced meters to provide timely, accurate, customer-specific outage information, as well as SCADA systems for real-time-confirmed switching and breaker operations. These systems track, group, and display outages for safe and efficient management of service restoration activities.

Q46. WHY IS THE COMPANY PROPOSING TO UPDATE THE OMS AT THIS TIME?

A. The Company's current OMS has limited capability for tracking the effects of automated outage reporting, requiring manual data correction during post-outage analysis. Further, the current OMS is a custom-built, legacy system that would require substantial customization and upgrades to integrate with an AMS. Through the meter reporting and two-way communications features of an AMS, a modern OMS will allow operators to accurately determine the number of customers affected by unscheduled and planned system outages within a central operating environment that includes data from SCADA, the advanced meters, and real-time system analysis, among other functionality. The results will be more efficient, and therefore faster, restoration of outages, particularly after storm-related outage events, and will limit the circumstances in which customers need to call the Company and report outages. More accurate outage data means that customers will have more accurate outage and restoration notifications, as well as improved accuracy of outage maps available to customers on the Company's website. Additional benefits of implementing a modern OMS along with an AMS include: a single, consolidated interface for outage management, SCADA, and other system activity; utilization of all available data (advanced meter data, trouble calls, SCADA) for enhanced outage analysis; the ability to manage large weather events more efficiently (*e.g.*, hurricanes and ice storms); management of outages directly from the real-time network view; and utilization of a dynamic network operations connectivity model. All of these features should enhance ETI's already outstanding storm restoration capabilities so that the Company can restore service to customers even more quickly and efficiently after outages.

Q47. PLEASE DESCRIBE THE VENDOR OF THE DMS AND OMS THAT WILL BE IMPLEMENTED, AND EXPLAIN WHY THAT VENDOR WAS SELECTED.

A. GE Grid Solutions, f/k/a Alstom Grid LLC ("Alstom"), an industry leader in DMS and OMS, is the vendor for the DMS and OMS. Alstom is a current supplier (including the SCADA system) and long-term partner of ETI, ESI, and other EOCs, which provides integration benefits through Alstom's knowledge of the legacy IT systems. In addition, ETI, with ESI support and along with other EOCs, has already participated in a co-development agreement with Alstom for a DMS, and as a result already co-owns the necessary software license for the DMS.

Q48. WHAT ARE THE ESTIMATED COSTS OF THE DMS AND OMS?

A. The total estimated cost of the DMS/OMS and the work to integrate those systems for all EOCs is $77 million, with ETI's share estimated to be $12 million.

VI. CYBER SECURITY AND DATA PROTECTION

Q49. HOW WILL DATA BEING COLLECTED, STORED, AND TRANSMITTED BY THE ADVANCED METERS BE PROTECTED?

A. The data that is collected, stored, and transmitted by the advanced meters will be protected with administrative, physical, and technological safeguards at various stages of the deployment. As Mr. Pierce describes, ETI has privacy and protection policies already in place, which will continue to be applicable to any new data collected through the AMS. Additionally, data protection and encryption designed to protect AMS data will be built into the advanced meters, communication systems, and data-processing systems. Cyber security industry standards were included as part of the procurement process, and cyber security controls for advanced meters and related systems that store and transmit data collected by advanced meters are being implemented. Standards and research such as those from the following entities are being used by the AMS vendors to guide the development and implementation of AMS cyber security controls to protect AMS components and customer data:

- NIST (National Institute of Standards and Technology)
- IEC (International Electrotechnical Commission)
- IEEE (Institute for Electrical and Electronics Engineers)
- NERC (North American Electric Reliability Corporation) Critical Infrastructure Protection (CIP) v5
- EPRI (Electric Power Research Institute)
- IETF (Internet Engineering Task Force)
- Other standards such as ANSI, ISO/IEC would also be applied to functional requirements

Q50. WHEN WILL THOSE CONTROLS BE IMPLEMENTED?

A. While the Company already has cyber security controls in place with respect to its current customer data storage systems, controls related to the new advanced meters and related infrastructure are being developed in conjunction with the AMS vendors as part of the AMS design phase. These new controls will be implemented during the build, test, and deployment phases of the project to ensure continued protection of Company and customer data after the AMS is deployed.

VII. SUMMARY OF AMS COST ESTIMATES

A. Implementation Costs

Q51. WHAT ARE THE ESTIMATED IMPLEMENTATION COSTS OF THE AMS DEPLOYMENT?

A. The costs of deploying the AMS are broken down into the main components described above plus "other" costs, described below. Table 2 below provides the breakdown of these costs, and additional detail is provided in Highly Sensitive Exhibit RWG-2.

Table 2
AMS Deployment Costs for ETI

Line item	**($M)**
Meters and installation	61.5
Communication network and head-end	15.6
MDMS	4.3
System integration	11.0
DMS/OMS	7.7
Other	36.2
Total implementation cost	**136.3**

Q52. WHAT ARE THE COMPONENTS OF THE "OTHER" CATEGORY?

A. The "other" category contains the following components:

- vendor costs for legacy systems – costs for existing vendors to modify and configure legacy IT systems so that the System Integrator can effectively integrate those systems with the ESB and new AMS components;
- dedicated internal resources – internal resources supporting the PMO for AMS, managing vendors and supporting deployment and business process changes;
- capitalized property tax – capitalized costs for property taxes incurred on year-end construction work-in-progress (CWIP) balances; and
- customer education – O&M expenses incurred to provide customer education on the benefits, functionality, and tools provided by the AMS technology.

Q53. DO THE ESTIMATED IMPLEMENTATION COSTS INCLUDE A CONTINGENCY AMOUNT?

A. Yes. Contingencies are a normal and essential component of an estimate for any large capital project. They provide an allowance for project uncertainty and risks at the time the estimate and associated budgets are prepared. As with any large scale multi-year project, there is the potential for risks that could affect the timing and/or cost of the AMS deployment. For instance, various conditions in both urban and rural areas within the Company's service area may affect the timing and cost of full deployment of the advanced meters. For example, I am aware that in urban areas, other utilities have experienced delays and increased costs where installers have been unable to connect meters at certain locations due to accessibility issues or unforeseeable, unique meter attachment configurations. In rural locations, other utilities have experienced delays and cost increases where their communications technology had difficulty reaching all of the metering components. Additionally, severe weather could delay the Company's meter deployment if resources are required to be diverted to storm restoration. Each of these situations is an example of risks that have emerged for other utilities on similar deployments, but whether or not the risk will materialize cannot be reasonably predicted at this stage of the project, and accordingly a contingency allowance is reasonable from a cost estimation perspective.

The Company included an estimated contingency to reflect the potential that it could incur additional costs related to specific risks, both known and unknown. However, the PMO will continue to exercise risk avoidance and mitigation measures and will update the contingency over the life of the project.

Q54. WHEN WILL THE COSTS OF THE COMPONENTS YOU IDENTIFIED ABOVE BE INCURRED?

A. A small portion of the costs began to be incurred in support of the AMS project in 2015 with the development of the vendor RFPs, high level project design, and cost estimation. Costs to design and implement the shared infrastructure for IT and communications systems will largely be incurred from 2016 through 2018. Following the installation of the common IT and communications infrastructure by the end of 2018, the communications network and advanced meter deployment is expected to begin. This meter deployment is expected to be complete by 2021 followed by the final communications network optimization that is expected to be complete in 2022. The estimated costs by year are provided in Highly Sensitive Exhibit RWG-2 attached to my Direct Testimony.

Q55. HAS THE COMPANY IMPLEMENTED A PROCESS TO TRACK SPENDING AND ENSURE COMPLIANCE WITH THE CONTRACTS AND BUDGETS?

A. Yes. Consistent with its standard accounting practices, the Company will budget and track the costs of each of the major activities through the use of project codes. The PMO will also oversee spending and compliance with budgets and contract terms. In addition, a cost and scheduling project manager will provide oversight and coordinate control with the PMO over project spending.

B. Ongoing Costs

Q56. WILL THERE BE ONGOING COSTS INCURRED BY THE COMPANY TO SUPPORT THE AMS OVER THE ASSUMED SEVEN-YEAR LIFE OF THE ADVANCED METERS AND INFRASTRUCTURE?

A. Yes. Ongoing O&M costs will be incurred for the vendor-supported systems as well as internal support for continued data analytics in the network operations center, unaccounted for energy detection, maintenance of the communications network, and various other meter services related to supporting the AMS.

Q57. HAS THE COMPANY ESTIMATED THE AMOUNT OF THOSE ONGOING COSTS?

A. Yes. The Company's estimated first full year of ongoing annual AMS-related O&M starting in 2022 is currently estimated to be approximately $3 million. Additional detail is provided in Highly Sensitive Exhibit RWG-3 attached to my Direct Testimony.

Q58. WHAT TYPES OF COSTS ARE INCLUDED IN THE O&M ESTIMATE PROVIDED ABOVE?

A. The costs included in the above estimate include:

- Meter Support – Includes the ongoing costs to support meter lab, meter testing and software support.
- Communications Network – Includes the ongoing costs for communication device additions, removals, and replacements; the backhaul network, firmware updates, analysis, troubleshooting, and issue resolution of event notifications; network performance analysis and optimization; vendor costs for the head-end system administration; and monitoring and hardware maintenance and backups.
- Software Systems Support – Includes the ongoing costs to support the MDMS, ESB, and the DMS and OMS. This includes costs for the system administration and monitoring, hardware maintenance and backups. The ongoing costs for the MDMS include ongoing data analytics and business operations center.
- Internal Support – Includes internal labor costs to support the new software systems and ongoing non-meter related mobile dispatch support.

VIII. CONCLUSION

Q59. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

Listing of Previous Testimony Filed by Rodney W. Griffith

DATE	TYPE	JURISDICTION	DOCKET NO.
November 1999	Direct	PUCT	20125
November 1999	Supplemental	PUCT	20125
September 2016	Direct	APSC	16-060-U
October 2016	Direct	CCNO	U-16-04
November 2016	Direct	LPSC	U-34320
November 2016	Direct	MPSC	2016-UA-261

This exhibit contains information that is **highly sensitive** and will be provided under the terms of the Protective Order (Confidentiality Disclosure Agreement) entered in this case.

This exhibit contains information that is **highly sensitive** and will be provided under the terms of the Protective Order (Confidentiality Disclosure Agreement) entered in this case.

This exhibit contains information that is **highly sensitive** and voluminous and will be provided under the terms of the Protective Order (Confidentiality Disclosure Agreement) entered in this case.

PUCT DOCKET NO. _____

APPLICATION OF ENTERGY	§	
TEXAS, INC. FOR APPROVAL OF	§	PUBLIC UTILITY COMMISSION
ADVANCED METERING SYSTEM	§	
(AMS) DEPLOYMENT PLAN, AMS	§	OF
SURCHARGE, AND NON-	§	
STANDARD METERING SERVICE	§	TEXAS
FEES	§	

DIRECT TESTIMONY

OF

JAY A. LEWIS

ON BEHALF OF

ENTERGY TEXAS, INC.

JULY 2017

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EXHIBITS

I. QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Jay A. Lewis. I am employed by Entergy Services, Inc. ("ESI")[1] as Vice President, Regulatory Policy. My business address is 639 Loyola Avenue, New Orleans, Louisiana 70113.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying before the Public Utility Commission of Texas ("PUCT" or the "Commission") on behalf of ETI.

Q3. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL, PROFESSIONAL, AND BUSINESS EXPERIENCE.

A. I have a Masters of Business Administration degree from Tulane University and a Bachelor of Business Administration degree in Accounting from the University of Louisiana at Monroe. I am a Certified Public Accountant and licensed to practice in Louisiana and Mississippi. I am a member of the American Institute of Certified Public Accountants and the Society of Louisiana Certified Public Accountants. I am also a member and past Chairman of the Accounting Standards Committee of the Edison Electric Institute.

[1] ESI is a subsidiary of Entergy Corporation that provides technical and administrative services to all of the Entergy Operating Companies ("EOCs"), which include Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc. ("ETI" or the "Company").

I began my career with ESI in 1999 as Director of Accounting Policy and Research. Beginning in 2004, I served as the Vice President and Chief Financial Officer of the Utility Operations Group. In 2008, I was named Vice President and Chief Accounting Officer-Designate for Enexus, a company proposed to be created by Entergy Corporation through a spinoff transaction. I assumed the position of Vice President, Finance for ESI in May 2010 and transferred to the position of Vice President, Regulatory Strategy in July 2011. I assumed the position of Vice President, Regulatory Policy in January 2014, and I recently transitioned into a part-time role in conjunction with my phased retirement from ESI. Prior to my career with ESI, I was employed in public accounting roles with Legier & Materne and Deloitte & Touche. In August 2016, I became an Instructor of Accounting at the University of Louisiana at Monroe.

Q4. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY COMMISSION?

A. Yes. A list of my prior testimony is attached as Exhibit JAL-1.

II. PURPOSE OF TESTIMONY

Q5. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I first provide an overview of the statutes and rules that are applicable and relevant to ETI's deployment of an Advanced Metering System ("AMS")[2] and this application, and I present the Company's request for limited waivers to the applicability of some of those rules. I also present and support the estimated AMS-related operational benefits (sometimes referred to as "operational savings") expected in connection with implementing ETI's AMS Deployment Plan. The operational benefits are used to calculate net operating cost savings as prescribed by Commission Rule 25.130(d)(5). I also make specific accounting proposals related to the useful life for the proposed advanced meters and related AMS infrastructure as well as address the unrecovered costs of the existing meters that will be retired from service and replaced by advanced meters. Finally, I explain the options available to a customer who may desire to opt out of having an advanced meter installed at their premises (non-standard metering service).[3]

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[2] The AMS that ETI proposes to implement includes advanced meters that enable two-way data communication, a secure and reliable communications network that supports two-way data communication, along with related and supporting systems, including a Meter Data Management System ("MDMS"), an Outage Management System ("OMS"), and a Distribution Management System ("DMS"), which ETI plans to integrate with its legacy information technology ("IT") systems via an Enterprise Service Bus ("ESB"). The advanced meters, two-way communications system, and MDMS are commonly referred to as advanced metering infrastructure, or "AMI." The functionalities of each of these are discussed in the Direct Testimony of Mr. Rodney W. Griffith.

[3] *See* 16 Tex. Admin. Code ("TAC") § 25.133.

III. OVERVIEW OF STATUTES AND RULES APPLICABLE TO ETI'S APPLICATION

Q6. PLEASE PROVIDE AN OVERVIEW OF THE STATUTES AND RULES APPLICABLE TO ETI'S APPLICATION, INCLUDING ETI'S PROPOSED DEPLOYMENT PLAN, AMS SURCHARGE, AND NON-STANDARD METERING SERVICE.

A. The Texas Legislature recently amended Section 39.452 of the Public Utility Regulatory Act,[4] the effect of which makes the Commission's Substantive Rules adopted under PURA Sections 39.107(h) and (k), and which include Rule 25.130, applicable to ETI.[5] The amendment further states that an "electric utility subject to this subchapter that elects to deploy an advanced meter information network shall deploy the network as rapidly as practicable to allow customers to better manage energy use and control costs"[6] The amendment also provides that the Commission shall ensure that any deployment plan and any related surcharge approved under the amendment shall be consistent with Commission rules related to AMS regarding (1) customer protections, (2) data security, privacy, and ownership, and (3) options given to customers to continue to receive service through a non-advanced meter.[7]

Commission Substantive Rule 25.130 addresses the AMS Deployment Plan and AMS Surcharge. The stated purposes of the Commission's Substantive

[4] TEX. UTIL. CODE ANN. §§ 11.001 – 66.0173 (WEST 2016) ("PURA").

[5] PURA § 39.452(k).

[6] PURA § 39.452(l).

[7] PURA § 39.452(k).

Rule 25.130 "are to authorize electric utilities to assess a nonbypassable surcharge to recover costs incurred for deploying advanced metering systems that are consistent with this section; increase the reliability of the regional electrical network; encourage dynamic pricing and demand response; improve the deployment and operation of generation, transmission and distribution assets, and provide more choices for electric customers."[8] Substantive Rule 25.130 defines the terms and conditions under which electric utilities can access a nonbypassable surcharge for recovery of costs associated with deploying advanced metering systems,[9] which include filing a Request for Approval of Deployment with the Commission.[10] In order to obtain a surcharge, electric utilities are required to show that the AMS contains certain minimum features as well as present the estimated costs for the AMS components, estimated net operating cost savings expected in connection with implementing the Deployment Plan, and the contracts for equipment and services associated with the Deployment Plan.[11] Other requirements of the Deployment Plan are included in subsection (d)(3)-(4) of Rule 25.130. The application, testimony, and exhibits that accompany ETI's Request for Approval of Deployment Plan and implementation of a surcharge provide all of the information required by Substantive Rule 25.130.

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[8] PURA § 39.452(k) similarly provides that an electric utility subject to that subchapter "that elects to deploy advanced metering and meter information networks may recover the reasonable and necessary costs incurred in deploying advanced metering and meter information networks."

[9] 16 TAC § 25.130(a).

[10] *Id.* at 25.130(d).

[11] *Id.* at 25.130(d)(5) and (g).

Commission Substantive Rule 25.133 addresses non-standard metering service and related fees for customers who do not want to receive service through an advanced meter. My testimony below discusses in greater detail how ETI plans to offer non-standard metering service (*i.e.,* an "opt-out policy") consistent with Substantive Rule 25.133.

Q7. IS A DEPLOYMENT PLAN AND STATEMENT OF AMS FUNCTIONALITY INCLUDED WITH ETI'S APPLICATION?

A. Yes. Consistent with Substantive Rule 25.130(d)(3) and (4), a Deployment Plan and AMS Statement of Functionality are included with ETI's application as Attachments A and B.

IV. WAIVERS

Q8. IS ETI REQUESTING ANY WAIVERS WITH RESPECT TO ITS DEPLOYMENT PLAN AND OTHER AMS-RELATED RULES OR REQUIREMENTS?

A. Yes. I describe each of the requested waivers below:

- Rule 25.130 contains a number of provisions and/or requirements that involve Retail Electric Providers and, by their terms, are only applicable in a deregulated retail electric market in which Retail Electric Providers provide retail electric service to customers and/or are specific to the Electric Reliability Council of Texas ("ERCOT") market and its protocols. Unless specifically noted, ETI has assumed that any such provisions and/or requirements do not apply to its Deployment Plan or AMS operations and requests a waiver to the extent that it is deemed that any such provisions and/or requirements would otherwise apply.

- In the event of a base rate case during the AMS deployment period ending in 2022, ETI requests that the costs being recovered through the AMS surcharge remain in the surcharge, rather than moving the cost of installed AMS equipment into base rates and decreasing the surcharge, as indicated by Rule 25.130(k)(4). This approach is consistent with prior AMS deployments in Texas.[12]
- Rule 25.133(c) provides for certain timeframes and notice requirements for customers requesting to opt out of receiving an advanced meter. As explained in Section VII of my testimony, the Company is seeking a waiver to the extent necessary to permit modification of certain timeframes in light of the fact that ETI will not begin deployment until 2019 and at this time does not yet have an approved Deployment Plan or approved non-standard metering services tariff.
- To the extent required, ETI seeks a waiver with respect to the requirement in Rule 25.133(c)(F)(i) that ETI offer non-standard metering service through disabling the communications technology in an advanced meter. As I explain below, the Rule only requires that option be available if it is "feasible." Although it is technically feasible to disable the communications technology, it is not feasible from a practical or cost perspective. Accordingly, and to the extent it is deemed necessary, ETI seeks a waiver of the requirement stated in 25.133(c)(F)(i).
- To the extent that the Commission's Rules 25.44, 25.130, and 25.500 are interpreted to require that ETI provide third-party direct access to

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[12] *AEP Texas Central Company's and AEP Texas North Company's Request for Approval of Advanced Metering System (AMS) Deployment Plan and Request for AMS Surcharges*, Docket No. 36928, Finding of Fact No. 16 (Dec. 17, 2009); *Texas-New Mexico Power Company's Request for Approval of Advanced Metering System (AMS) Deployment and AMS Surcharge*, Docket No. 38306, Finding of Fact No. 18 (July 8, 2011); *Oncor Electric Delivery Company LLC's Request for Approval of Advanced Metering System (AMS) Deployment Plan and Request for AMS Surcharge*, Docket No. 35718, Finding of Fact No. 30 (Aug. 29, 2008).

customer AMS data (subject to customer consent), ETI requests a waiver at this time. As explained by Company witness Mr. H. Vernon Pierce, the customer web portal that is currently under development will provide customers access to their interval data (on a day-after basis), and it will have functionality that allows customers to download their AMS data in an industry-standard file format and then share that file with whomever they choose. With respect to third-party direct access to customer AMS data, the Company is still exploring the various methods by which such access might be feasible, as well as studying the related privacy and data security aspects of providing third-party direct access. Accordingly, ETI requests that it be afforded time to study the implications of third-party direct access with respect to its AMS deployment and associated development of its customer web portal.

- As explained by Company witness Mr. Rodney Griffith, the Company is seeking a waiver of Rule 25.130(g)(1)(c) only to the extent that loads that currently have poly-phase, class 200 (200 amp rating) meters, which includes commercial customers and some residential customers, will not have a service switch until a poly-phase advanced meter with those devices become available in the market.
- Rule 25.130(c)(4)(E) requires that the Deployment Plan include a deployment schedule by specific area (geographic information). While Mr. Griffith provides a preliminary deployment schedule by year, with installation not scheduled to begin until 2019, the detailed deployment plan by specific area is still being developed with the installation vendor. A deployment schedule by specific areas is expected by the end of 2017, and ETI will provide that information when it is available. Accordingly, ETI seeks a temporary waiver of the requirement stated in Rule 25.130(c)(4)(E).

V. ESTIMATED NET OPERATING COST SAVINGS

A. Overview

Q9. HAS THE COMPANY PREPARED AN ANALYSIS THAT QUANTIFIES NET OPERATING COST SAVINGS THAT ARE EXPECTED TO RESULT FROM ETI'S AMS DEPLOYMENT?

A. Yes. I have conducted an analysis that quantifies several of the expected operational benefits from the AMS deployment ("Operational Benefits"). The Operational Benefits include: (i) routine meter reading; (ii) meter services; (iii) reduced customer receivable write-offs; and (iv) field data collection system. I will describe later in this testimony how each of these benefits is calculated. I also explain why the Company has employed a seven-year useful life for the AMS assets in calculating these benefits. Mr. Griffith presents the post-AMS deployment operational costs, and ETI witness Mr. Rich Lain then describes how the quantified Operational Benefits and post-AMS deployment operational costs are netted to calculate the net operational cost savings and the resulting AMS revenue requirement and surcharge.

Q10. ARE THERE OTHER BENEFITS OF AN AMS THAT HAVE NOT BEEN QUANTIFIED IN THIS APPLICATION?

A. Yes. The Company has quantified many of the operational benefits of an AMS, which are described later in my testimony; however, there are a number of other benefits that have been identified by other utilities in conjunction with their respective AMS deployments, including reductions in energy consumption, peak capacity, and unaccounted for energy ("UFE"). Those types of benefits are, for the most part, typically reflected as fuel savings on customers' bills. Additional potential benefits that have also been identified include increased billing accuracy and reduced customer service call volume. Mr. Pierce describes, qualitatively, some of the other potential benefits in more detail in his Direct Testimony.

Q11. HOW WERE AMS COSTS FOR ETI DERIVED?

A. The costs for the meter hardware, meter installation, network interface cards ("NIC"), communications network devices and components, and the related internal resources and contractors will be directly incurred by ETI and were computed based on the current number of customer meters and the expected increase in customer meters by the end of the deployment period, excluding transmission voltage customers.[13] Final costs will be tied to the actual number of meters and meter types deployed. Certain components of the AMS deployment, such as the IT systems and project support, will be shared by the EOCs. This approach results in lower overall costs to customers as compared to each EOC maintaining separate systems, as discussed by Mr. Griffith. Specifically, the cost of the communications network design and the head-end component of the communications network, the MDMS, the DMS, the OMS, certain software licensing costs, the costs related to the meter testing facility, as well as the overall system integration and project support will be incurred by ESI and are assigned to

[13] The recent amendment to Section 39.452 of PURA exempts transmission voltage customers from receiving an AMS meter or paying the AMS surcharge associated with the proposed Deployment Plan.

the EOCs based on the total number of customers located in each EOC's jurisdiction.

Q12. WHY HAS THE COMPANY EMPLOYED A SEVEN-YEAR USEFUL LIFE IN DETERMINING THE BENEFITS TO CUSTOMERS ASSOCIATED WITH THE AMS DEPLOYMENT?

A. The Company employs a seven-year useful life because Rule 25.130(k)(3) provides that "the commission prefers the stability of a levelized amount, and an amortization period ranging from five to seven years, depending on the useful life of the meter." Further, other utilities in Texas that have approved AMS Deployment Plans utilized seven-year useful lives for the advanced meters.[14]

Q13. PLEASE SUMMARIZE THE NET OPERATIONAL COST SAVINGS.

A. Table 1 below provides a summary of the net operational cost savings on both a nominal and net present value ("PV") basis.

[14] *Application of CenterPoint Energy Houston Electric, LLC for Approval of Deployment Plan and Request for Surcharge for an Advanced Metering Syste*m, Docket No. 35639, Finding of Fact No. 30 (Dec. 22, 2008); AEP Docket No. 36928, Finding of Fact No. 30; TNMP Docket No. 38306, Finding of Fact No. 34; Oncor Docket No. 35718, Finding of Fact No. 24.

Table 1
Summary of Net Operating Cost Savings

		Nominal ($M)	PV ($M, 2016)
	Quantified Operational Benefits		
1	Routine Meter Reading	$39.2	$22.1
2	Meter Services	$21.7	$12.2
3	Reduced Customer Receivables Write-offs	$1.3	$0.7
4	Field Data Collection System	$0.4	$0.2
5	**Total AMS Operational Benefits**	$62.6	$35.3
	Less:		
6	**Total AMS Operational Costs**	$29.2	$17.1
7	Net AMS Operational Cost Savings	$33.4	$18.2

B. Routine Meter Reading

Q14. PLEASE DESCRIBE THE ROUTINE METER READING BENEFIT THAT IS REFLECTED IN TABLE 1.

A. As described in more detail by Mr. Pierce, the Company incurs expenses for contract personnel (and their vehicles) to physically travel to and read customer meters each month. The two-way communications functionality of the advanced meters along with the communications and IT infrastructure being deployed with the AMS allows meters to be read remotely, and therefore eliminates the need for routine meter reading trips. As reflected in Table 1, over the estimated useful life of the AMS, the analysis shows benefits of $39.2 million on a nominal basis compared to a scenario in which an AMS is not deployed, *i.e.*, maintaining the status quo. On a PV basis, the benefits are $22.1 million. *See* HSPM Exhibit JAL-2 for the supporting calculations.

Q15. HOW DID THE COMPANY ESTIMATE THE LEVEL OF ROUTINE METER READING COSTS THAT COULD BE AVOIDED?

A. Mr. Pierce supports the estimated amount of annual Operations and Maintenance ("O&M") expense for routine meter reading and internal support and management of meter reading contracts. The amount budgeted for 2016 is expected to grow by the first year of meter deployment in 2019. In calculating the total benefits expected over the useful life of the AMS, the Company made the following assumptions:

- The meter reading contracts are sourced on a three-year cycle with the first contract renegotiations after the expected implementation of AMS by ETI assumed to occur in 2021 (assuming the status quo, *i.e.*, no AMS implementation). ETI would expect an increase of a certain percentage over the 2019 levels upon renewal of the contracts and every three years thereafter for subsequent renewals. These anticipated increases are consistent with the expected inflation rate. *See* HSPM Exhibit JAL-2.
- A 2% annual inflation rate was used for non-contract meter reading costs such as internal support and management of the meter reading contracts.
- The benefits were scaled to match the expected meter deployment schedule. For example, as reflected in the meter deployment schedule described by Mr. Griffith, it is expected that 36% of ETI's customers would receive advanced meters by the end of 2019, so the routine meter reading benefits for 2019 are scaled proportionally to match the average percentage installation rate for that timeframe. As existing meters continue to be replaced over the three-year deployment period (2019-2021), the benefits are increased proportionally.

C. Meter Services Benefit

Q16. PLEASE DESCRIBE THE METER SERVICES BENEFIT THAT IS REFLECTED IN TABLE 1.

A. As described in more detail by Mr. Pierce, the Company incurs expenses for personnel (and their vehicles) to travel to customer premises for a variety of meter-related services, which include service starts and stops, certain meter re-reads, and service disconnections related to non-payment, as well as any subsequent reconnections. The advanced meters and related communications infrastructure will eliminate the need for the vast majority of these physical trips. As reflected in Table 1, over the useful life of the AMS, the analysis indicates benefits of $21.7 million on a nominal basis compared to a scenario in which an AMS is not deployed, *i.e.*, maintaining the status quo. On a PV basis, the benefits are $12.2 million. *See* HSPM Exhibit JAL-2 for the supporting calculations.

Q17. HOW DID THE COMPANY ESTIMATE THE METER SERVICES BENEFITS?

A. The Company's estimates are based on historical experience that 90% of electric meter services payroll and vehicle costs are O&M expenses (the remaining 10% are associated with capital additions), and that 100% of the supporting mobile dispatch payroll and contracted meter services costs are O&M. Based upon the application of those percentages to the budgeted 2016 meter services costs for payroll, vehicle, mobile dispatch, and contracted meter services that Mr. Pierce explains, the Company estimated the annual meter services O&M expenses that will be eliminated as a result of the AMS. In calculating the total benefits over the expected life of the AMS, the Company assumed a 2% annual inflation rate that was applied to the 2016 budgeted meter services costs and scaled the benefits to match the expected meter deployment schedule, as discussed previously.

D. Reduced Customer Receivables Write-Offs

Q18. PLEASE DESCRIBE THE REDUCED CUSTOMER RECEIVABLES WRITE-OFFS BENEFIT THAT IS REFLECTED IN TABLE 1.

A. After a disconnect ticket to suspend service for non-payment is issued to field personnel, it takes additional time to physically go to the customer premises and disconnect the service at the meter. Eliminating the lag between scheduling and dispatching a technician to disconnect electric service through use of the remote disconnect feature of advanced electric meters reduces the amount of revenue that becomes uncollectible and is ultimately reflected in rates through bad debt expense. As reflected in Table 1, over the estimated useful life of the AMS, the analysis shows benefits of $1.3 million on a nominal basis compared to a scenario in which an AMS is not deployed. On a PV basis, the benefits are $0.7 million.

Q19. HOW DID THE COMPANY ESTIMATE THE REDUCED WRITE-OFF BENEFITS?

A. The Company estimated the total write-off amount each year through 2020 and adjusted it proportionally based upon the expected reduction in disconnection time described above. In 2019, the estimated total write-off amount is

$3.2 million. The Company calculated as a percentage the number of days that are eliminated from the time it normally takes to disconnect a customer for non-payment as a result of the remote disconnect feature of advanced electric meters. This percentage was applied to the 2019 estimated annual write-off amount of $3.2 million to derive an estimated dollar benefit of $162,000 annually. Similar to the routine meter reading and meter services benefit calculations, the estimated benefits were escalated annually at a 2% inflation rate and also scaled to match the expected meter deployment schedule. See HSPM Exhibit JAL-2 for the supporting calculations.

E. Field Data Collection System Benefit

Q20. WHAT IS THE BENEFIT ASSOCIATED WITH ELIMINATING FIELD DATA COLLECTION SYSTEM SUPPORT?

A. There are a number of handheld electronic field data collection system ("FCS") devices used by the Company's contract meter readers to perform manual meter reads today. There are annual O&M costs associated with software and warranty necessary to provide ongoing support. In the future, meter reading will be performed remotely, and these costs will no longer be required.[15]

[15] Some meter reading equipment may be retained to support readings needed for exception situations, although the Company does not plan to incur O&M expense for maintaining that equipment, and it does not plan to replace it after it stops functioning.

Q21. WHAT DID THE COMPANY CALCULATE AS THE PROJECTED BENEFIT ASSOCIATED WITH ELIMINATING THE FCS SUPPORT?

A. The Company estimated future avoided O&M costs would amount to a benefit of $54,000 in 2019. In calculating total benefits over the expected useful life of the AMS, the following assumptions were made:

- Costs of the warranty and software support increase at an assumed annual vendor inflation rate.
- The warranty and software benefits were scaled to match the expected meter deployment schedule.

This results in a nominal benefit of $446,000, which is $250,000 on a present value basis. See HSPM Exhibit JAL-2 for the supporting calculations.

VI. EXISTING ELECTRIC METERS

Q22. HOW DOES THE COMPANY PROPOSE TO RECOVER THE REMAINING UNDEPRECIATED BOOK VALUE OF THE EXISTING METERS THAT WILL BE RETIRED WITH THE DEPLOYMENT OF ADVANCED METERS?

A. Pursuant to Substantive Rule 25.130(k)(4), the Company is seeking confirmation from the Commission that it will be allowed to continue to include the remaining book value of the existing meters in rate base, consistent with the normal treatment of asset retirements, and to depreciate those assets using current depreciation rates. Under this proposal, the remaining book value of the retired meters will continue to be depreciated until those costs are fully recovered, just as if they had not been retired. As such, the retirement of the existing meters will not have any impact on future rates. That is, the future revenue requirement associated with the existing meters will not change as a result of their retirement.

Q23. WHAT IS THE REMAINING BOOK VALUE OF THE EXISTING METERS, AND WHAT DEPRECIATION RATE IS CURRENTLY USED TO RECOVER THESE COSTS?

A. The book value and annual depreciation rate of the existing meters as of December 31, 2016 are reflected below in Table 2. It should be noted that the Federal Energy Regulatory Commission ("FERC") account for meters also includes ancillary equipment that will remain in service as well as meters for all customer classes. The costs related to the ancillary equipment are not included in the table below as they will remain in service post-AMS deployment.

Table 2
Existing Meter Net Book Value

	Plant in Service	Accumulated Reserve	Net Book Value	Depreciation Rate	Annual Depreciation Expense	Remaining Life
ETI	$41,020,907	$13,453,144	$27,567,763	4.93%	$2,022,331	14

Q24. IS THE COMPANY'S PROPOSAL CONSISTENT WITH THE COMMISSION'S SUBSTANTIVE RULES AND TREATMENT IN PRIOR AMS DEPLOYMENTS?

A. Yes. The fundamental rationale for the continued recovery of and on the Company's remaining investment in existing meters is that these amounts represent prudent investments that have not yet been fully recovered from customers. It is common utility ratemaking practice to include in rate base the unrecovered cost of assets that are retired early, and there is no reason to depart from that practice in this instance. The retirement of the existing meters will be contingent upon Commission approval of the Deployment Plan, which was filed by ETI consistent with Legislative authority to implement an AMS for the benefit of its customers. Accordingly, there is no basis to disallow or otherwise alter the method or timing of recovery of these unrecovered costs, because the Company has not acted improperly in either investing in or retiring these existing meters.

Moreover, Substantive Rule 25.130(k)(4) provides that:

> [i]f the commission conducts a general base rate proceeding while a surcharge under this section is in effect, then the commission shall include the reasonable and necessary costs of installed AMS equipment in the base rates and decrease the surcharge accordingly, and *permit reasonable recovery of any non-AMS metering equipment that has not yet been fully depreciated but has been replaced by the equipment installed under an approved Deployment Plan.*[16]

Finally, other utilities in Texas that have received approval to deploy an AMS have received approval for continued recovery of and on existing meters.[17]

[16] 16 TAC § 25.130(k)(4) (emphasis added).

[17] CenterPoint Docket No. 35639, Findings of Fact Nos. 91-93; AEP Docket No. 36928, Findings of Fact Nos. 56-58; TNMP Docket No. 38306, Findings Of Fact Nos. 56-57.

VII. NON-STANDARD METERING SERVICE

Q25. IS THE COMPANY PROVIDING CUSTOMERS WITH AN OPTION TO REQUEST NON-STANDARD METERING SERVICE?

A. Yes. The amendment to PURA Section 39.452 that I mentioned above requires that ETI's AMS deployment plan is consistent with Commission rules related to options given to customers to receive metering service through a non-advanced meter.[18] Commission Substantive Rule 25.133 prescribes the terms and conditions under which customers may opt out of AMS metering and utilize a non-standard meter for electric metering purposes. The Company is proposing an opt-out policy consistent with the Commission's Rule.

Q26. DOES A CUSTOMER'S VOLUNTARY CHOICE TO OPT OUT OF ETI'S INSTALLATION OF AN ADVANCED METER INCREASE THE COSTS TO SERVE THAT CUSTOMER?

A. Yes, and Substantive Rule 25.133 requires that those customers pay the costs associated with providing non-standard metering service.[19] As described below, some of the costs associated with a customer choosing to opt out depend upon the timing of the opt-out request. In addition, regardless of when a customer opts out of advanced metering, the Company will incur up-front costs associated with a truck roll, the purchase of meter locks, processing of the opt-out paperwork, and billing set-up costs to make the necessary modifications to the Company's

[18] PURA § 39.452(k)(2)(C).

[19] *See* 16 TAC § 25.133(e).

customer billing system. Company witness Mr. Pierce describes these costs in more detail in his Direct Testimony. There will also be ongoing monthly costs associated with the need to continue to manually read the meter and manage billing and customer data. Mr. Pierce also describes those costs.

Q27. HOW DOES ETI PROPOSE TO HANDLE OPT-OUT REQUESTS?

A. Rule 25.133(c) provides for certain notice requirements and timeframes for handling out-out requests depending on where the utility is in terms of its deployment and when it began offering non-standard metering service. The rule was written at a time when many of the ERCOT utilities had already completed deployment or were well down that path when they began offering non-standard metering service. To that end, Rule 25.133(c)(1)(A), which applies to a utility that has completed its deployment, clearly is not applicable to ETI's situation.

Rule 25.133(c)(1)(B) appears to apply to a utility that has started but not completed deployment. Since ETI has not yet begun deployment, and at the time of this filing does not even have a Commission-approved Deployment Plan, the Company does not believe this provision should be applicable as written. However, the Company believes that the intent of Rule 25.133(c)(1)(B)(i) is to provide a mechanism by which customers can request to opt out sometime in advance of the date that an advanced meter would otherwise be installed at their premises. Similarly, Rule 25.133(c)(1)(B)(ii) appears intended to allow a customer to request non-standard metering service more contemporaneously when a utility "attempts to install an advanced meter." In compliance with revised

PURA Section 39.452(k)(2), which requires that ETI's deployment plan be consistent with rules related to options given consumers to continue to receive service through a "non-advanced meter," the Company proposes the following procedures for complying with the notice and timing requirements of Rule 25.133(c):[20]

[20] To the extent it were determined that Rule 25.133(c) applies as written, ETI seeks a waiver and incorporation of the procedures proposed in this filing.

Table 3

Advanced meter installed at the customer's premises at the time of the request?	Timing of customer's request to ETI for non-standard metering service:	ETI will provide the required notice to customer	Deadline for customer to return signed, opt-out acknowledgement form and submit payment for applicable up-front fee to ETI:
No	Greater than 90 days before ETI is scheduled to install an advanced meter at the customer's premises	Approximately 90 days prior to the date the customer is scheduled to receive an advanced meter[21]	60 days from date of ETI's notice[22]
No	Less than 90 days before ETI is scheduled to install an advanced meter at the customer's premises	ETI will provide notice promptly following customer's request[23]	60 days from date of ETI's notice[22]
No	During the attempt to install an advanced meter at the customer's premises	ETI will provide notice promptly following customer's request[23]	60 days from date of ETI's notice[22]
Yes	After an advanced meter has been installed at the customer's premises	Within seven days of being contacted[24]	Upon receipt[25]

[21] In this situation, ETI will track the customer's request to opt out and inform the customer that ETI will follow up with their request closer to when advanced meters will be deployed in their area. At that time, the required notice will be provided via certified mail return receipt requested as required by Rule 25.133.

[22] In accordance with Substantive Rule 25.133(c)(1)(D)(v), if the signed, written acknowledgement and payment are not received within 60 days, ETI will install an advanced meter on the customer's premises.

[23] Consistent with 16 TAC § 25.133(c), the notice will be provided via certified mail return receipt requested.

[24] *See* Substantive Rule 25.133(c)(1)(C).

[25] In this situation, ETI will not initiate non-standard metering service for that customer until the acknowledgement form and applicable up-front fee is received. *See* Substantive Rule 25.133(c)(1)(C).

Q28. WHAT IS THE PURPOSE OF THE NOTICE AND ACKNOWLEDGMENT FORM?

A. The purpose of the notice and acknowledgment form is to ensure that the customer has been informed of, and has acknowledged, the disadvantages and costs associated with choosing non-standard metering service. By signing the acknowledgment form, the customer demonstrates an understanding and acceptance of the fees, requirements, and limitations associated with non-standard metering service. The proposed written acknowledgment form is attached as Exhibit JAL-3.

Q29. WHAT INFORMATION WILL BE INCLUDED IN THE ACKNOWLEDGMENT FORM?

A. Consistent with Substantive Rule 25.133 and the forms used by other Texas utilities, the customer will be informed of the requirement to pay all associated costs of non-standard metering service, the ongoing costs associated with the manual reading of the meter, and other fees and charges associated with non-standard metering service, *e.g.*, meter re-reads and disconnects/reconnects for non-payment.[26] The acknowledgment form will list the up-front and on-going fees associated with choosing non-standard metering service.[27] The acknowledgment form also explains that the customer may experience longer

[26] 16 TAC § 25.133(c)(1)(D)(i).

[27] 16 TAC § 25.133(c)(1)(D)(ii).

restoration times in the event of a power outage.[28] Finally, for customers who notified the Company of their desire to opt out before an advanced meter has been installed, the form explains that the applicable up-front fee and signed acknowledgment form must be received within 60 days or an advanced meter will be installed.[29]

Q30. HOW LONG WILL THE COMPANY MAINTAIN THE ACKNOWLEDGMENT FORMS?

A. Consistent with Rule 25.133(c)(1)(E), the Company will retain the form for at least two years after the non-standard meter is removed from the premises.

Q31. WHAT NON-STANDARD METERING OPTIONS ARE AVAILABLE IF A CUSTOMER CHOOSES TO OPT OUT OF HAVING AN ADVANCED METER INSTALLED AT THEIR PREMISES?

A. Commission Rule 25.133(c)(1)(F) identifies four non-standard metering options: (1) disabling communications technology in an advanced meter if feasible; (2) if applicable, allowing the customer to continue to receive metering service using the existing meter if the TDU[30] determines that it meets applicable accuracy standards; (3) if commercially available, an analog meter that meets applicable

[28] 16 TAC § 25.133(c)(1)(D)(iii).

[29] 16 TAC § 25.133(c)(1)(D)(v).

[30] A TDU is a transmission and distribution utility. Although this rule does not on its face apply to a bundled utility such as ETI, ETI is proposing that its non-standard meter service follow the requirements of the rule as a reasonable approach to the issue and as consistent with PURA § 39.452.

meter accuracy standards; and (4) a digital, non-communicating meter. ETI does not intend to offer option (1), disabling communications technology, because, while it is feasible from a technical perspective, it is not feasible from a practical or cost perspective. For security reasons, the AMS is not designed such that the NIC that is installed in an advanced meter can be remotely disabled, so an in-person visit and associated technician time would be incurred both in disabling the NIC on site and then again in re-enabling the NIC when the customer moves or decides to discontinue non-standard metering service. In addition, disabling a NIC on site requires special equipment and additional training that would not be necessary with simply removing an advanced meter and replacing it with a non-communicating digital meter. Accordingly, providing option (1) would be more costly to the customer than the non-communicating digital meter option, which at the end of the day performs the same function. Finally, the Company believes that the health, safety, and privacy concerns of the typical customer who opts out may not be addressed by this option because there is no meaningful way for that customer to confirm that the disabled advanced meter is in fact no longer communicating (or no longer capable of communicating). For this reason, the Company understands that virtually no customers have selected that option when it was offered by other Texas utilities that have implemented AMS.[31]

[31] For example, in the compliance report submitted to the PUCT by Oncor in July 2016 (Docket No. 44129), the utility reported that as of that date, only one non-standard metering customer had selected this option. *See* http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/44129_12_902936.PDF.

Accordingly, ETI does not believe that option (1) is practically feasible, and to the extent necessary, requests waiver of that requirement.

ETI does not intend to offer option (3), an analog meter. ETI understands that new analog meters are no longer commercially available. Further, ETI has been installing digital meters as standard metering equipment for many years now, and it does not keep analog meters in inventory. However, if a customer chooses to opt out prior to the installation of an advanced meter, the Company proposes to allow the customer to keep the existing meter (including an analog meter) following an inspection of that existing meter for safety-related issues or tampering issues and a test to ensure the meter meets the Company's and the Commission's applicable standards for accuracy. By conducting a meter inspection and test, the Company will be able to identify potential safety issues, inaccurate or defective meters, as well as evaluate whether tampering or theft may be occurring, and install a new meter seal barrel lock on the meter.

If a customer chooses to opt out after an advanced meter has already been installed at their premises, then the only option would be replacement with a digital, non-communicating meter, including installing the appropriate seal and barrel lock.

Q32. PLEASE EXPLAIN THE OPT-OUT FEE STRUCTURE.

A. Consistent with Substantive Rule 25.133(e), the Company is proposing that the up-front costs associated with the customer billing set-up, meter locks, trip charge, and processing of opt-out paperwork be charged to the opt-out customer